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Monday
July 23, 1979

Highlights

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Highlights

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Presidential Documents

Title 3—

The President

Executive Order 12147 of July 19, 1979

United States International Development Cooperation Agency

By the authority vested in me as President of the United States of America by Section 9 of Reorganization Plan No. 2 of 1979, both Houses of Congress having defeated a resolution of disapproval (S. Res. 140, 125 Cong. Rec. S. 8829 (July 9, 1979); H. Res. 231, 125 Cong. Rec. H. 5729 (July 11, 1979)), it is hereby ordered that Sections 2, 3, and 4 of that Plan, providing for the offices of Director, Deputy Director, and Associate Directors, are effective immediately.

Jimmy Carter

THE WHITE HOUSE,
July 19, 1979.

[FR Doc. 79-22879
Filed 7-20-79; 10:48 am]
Billing code 3195-01-M

Rules and Regulations

Federal Register
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Monday, July 23, 1979

This section of the FEDERAL REGISTER contains regulatory documents having general applicability and legal effect, most of which are keyed to and codified in the Code of Federal Regulations, which is published under 50 titles pursuant to 44 U.S.C. 1510.
The Code of Federal Regulations is sold by the Superintendent of Documents. Prices of new books are listed in the first FEDERAL REGISTER issue of each month.

DEPARTMENT OF AGRICULTURE

Federal Crop Insurance Corporation

7 CFR Part 402

Raisin Crop Insurance Regulations; Correction

AGENCY: Federal Crop Insurance Corporation, USDA.

ACTION: Correction of Typographical Error.

SUMMARY: This action corrects a typographical error in the Raisin Crop Insurance Regulations as published in the Federal Register on Monday, June 25, 1979 (44 FR 36929), as final rule.

EFFECTIVE DATE: July 23, 1979.

FOR FURTHER INFORMATION CONTACT: Peter F. Cole, Secretary, Federal Crop Insurance Corporation, U.S. Department of Agriculture, Washington, D.C. 20250, 202-447-3325.

SUPPLEMENTARY INFORMATION: On April 6, 1979, the Board of Directors of the Federal Crop Insurance Corporation adopted regulations for insuring raisins effective with the 1979 and succeeding crop years. These regulations were published in the Federal Register as a final rule on June 25, 1979 (44 FR 36929). A typographical error was noted and is hereby corrected as follows:

On page 36932, section 12(a) is corrected in the 11th line thereof to read "(b) of this section and section 6 of the * * *"

Dated: July 16, 1979.

Peter F. Cole,

Secretary, Federal Crop Insurance Corporation.

[FR Doc. 79-22691 Filed 7-20-79; 8:45 am]

BILLING CODE 3410-08-M

7 CFR Part 417

Sugarcane Crop Insurance Regulations; Corrections

AGENCY: Federal Crop Insurance Corporation, USDA.

ACTION: Corrections of Omission Errors.

SUMMARY: This action corrects two omissions in the Sugarcane Crop Insurance Regulations as published in the Federal Register on Thursday, June 21, 1979 (44 FR 36161), as Final Rule.

EFFECTIVE DATE: July 23, 1979.

FOR FURTHER INFORMATION CONTACT: Peter F. Cole, Secretary, Federal Crop Insurance Corporation, U.S. Department of Agriculture, Washington, D.C. 20250, 202-447-3325.

SUPPLEMENTARY INFORMATION: On June 8, 1979, the Board of Directors of the Federal Crop Insurance Corporation adopted regulations for insuring sugarcane crops effective with the 1980 and succeeding crop years. These regulations were published in the Federal Register as a final rule on June 21, 1979 (44 FR 36161). Two ommissions were noted and are herby corrected, as follows:

1. On page 36164, section 8(b)(1) is corrected to read "multiplying the insurable acreage of standard sugarcane on the unit by the applicable production guarantee per acre, which product shall be the production guarantee for the unit."

2. On page 36165, section 1(k) of the Appendix is corrected to read "'Standard sugarcane' means net sugarcane containing the percent sucrose in the normal juice or in the cane and, where applicable, the percent purity factor in normal juice as shown on the actuarial table."

Dated: July 16, 1979.

Peter F. Cole,

Secretary, Federal Crop Insurance Corporation.

[FR Doc. 79-22690 Filed 7-20-79; 8:45 am]

BILLING CODE 3410-08-M

Agriculture Marketing Service

7 CFR Part 965

Tomatoes Grown in the Lower Rio Grande Valley in Texas; Expenses

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Final rule.

SUMMARY: This regulation authorizes expenses for the functioning of the Texas Valley Tomato Committee. It enables the committee to finance a marketing research and development project from operating reserve funds.

EFFECTIVE DATE: July 1, 1979.

FOR FURTHER INFORMATION CONTACT: Peter G. Chapogas (202) 447-5432.

SUPPLEMENTARY INFORMATION: *Findings.* Pursuant to Marketing Order No. 965, as amended (7 CFR Part 965), regulating the handling of tomatoes grown in the counties of Cameron, Hidalgo, Starr and Willacy in the State of Texas, effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601-674), and upon other information, it is found that the expenses which follow will tend to effectuate the declared policy of the act.

It is further found that it is impracticable and contrary to the public interest to provide 60 days for interested persons to file comments or to engage in public rulemaking procedure, and that good cause exists for not postponing the effective date of this section until 30 days after publication in the Federal Register (5 U.S.C. 553). No requirements are being imposed as the funds in the operating reserve had been collected several seasons ago. The time when the need for this project became known versus the time it must begin to be effective is too short to allow such an extended schedule. Handlers and other interested persons were given an opportunity to submit information and views on the expenses at an open public meeting of the committee held July 2, 1979, in McAllen. To effectuate the declared purposes of the act it is necessary to make these provisions effective as specified.

Note.—The budget has not been determined significant under the USDA criteria for implementing Executive Order 12044.

7 CFR Part 965 is amended by adding a new § 965.214 as follows:

§ 965.214 Expenses.

The reasonable expenses that are likely to be incurred during the period beginning July 1, 1979, by the Texas Valley Tomato Committee for its maintenance and functioning, and for such purposes as the Secretary determines to be appropriate will amount to $1,250.

Terms used in this section have the same meaning as when used in Marketing Order No. 965.

(Secs. 1–19, 48 Stat. 31, as amended; (7 U.S.C. 601–674)).

Dated: July 17, 1979.

D. S. Kuryloski,

Acting Deputy Director, Fruit and Vegetable Division, Agricultural Marketing Service.

[FR Doc. 79-22650 Filed 7-20-79; 8:45 am]

BILLING CODE 3410-02-M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket Number 79-CE-12-AD; Amdt. 39-3517]

Airworthiness Directives; Cessna Models 205, 206, U206/TU206, P206/TP206, 207/T207, 210/T210 and P210 Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This Amendment adds a new Airworthiness Directive (AD) applicable to Cessna Models 205, 206, U206/TU206, P206/TP206, 207/T207, 210/T210 and P210 airplanes. It requires installation of a placard and a special procedure card or revision to the Pilot's Operating Handbook, as applicable. This AD provides the pilot with information that will aid him during instances of fuel flow fluctuations or power interruptions due to fuel system vapor. This action is necessary because vapor blockage of the fuel system may occur and total engine power loss may result.

EFFECTIVE DATE: July 26, 1979. Compliance: Within 25 hours time-in-service after the effective date of this AD.

ADDRESSES: Cessna Single Engine Customer Care Service Information Letter SE 79-25, dated April 30, 1979, and Supplement No. 1 thereto dated June 4, 1979, applicable to this AD, may be obtained from Cessna Aircraft Company, Marketing Division, Attention: Customer Service Department, Wichita, Kansas 67201; Telephone (316) 685-9111. Copies of the service letter and supplement cited above are contained in the Rules Docket, Office of the Regional Counsel, Room 1558, 601 East 12th Street, Kansas City, Missouri 64106 and at Room 916, 800 Independence Avenue, SW., Washington, D.C. 20591.

FOR FURTHER INFORMATION CONTACT: Jack Pearson, Wichita Engineering and Manufacturing District Office, FAA, Room 238, Mid-Continent Airport, Wichita, Kansas 67209; Telephone (316) 942-7927.

SUPPLEMENTARY INFORMATION: Instances of fuel flow fluctuations, power interruptions, forced landings and accidents have occurred on the airplanes that are the subject matter of this AD. Investigations and testing by the manufacturer and the FAA have demonstrated the inability of the fuel system on these airplanes to purge itself of vapor and air under certain circumstances. To provide the pilot with information which will enable him to recognize an impending fuel system vapor lock and operating procedures to preclude power loss, the manufacturer has issued Cessna Single Engine Customer Care Service Information Letter SE 79-25 dated April 30, 1979, and Supplement No. 1 thereto dated June 4, 1979. This information is incorporated on a placard and a special procedure card or revision to the Pilot's Operating Handbook, as applicable. Further study is in process which may result in additional regulatory action. Since the condition described herein is likely to exist or develop in other airplanes of the same type design, the FAA is issuing an AD making compliance with the substance of aforementioned service letter and supplement mandatory.

The FAA has determined that there is an immediate need for a regulation to assure safe operation of the affected airplanes. Therefore, notice and public procedure under 5 U.S.C. 553(b) is impracticable and contrary to the public interest and good cause exists for making the amendment effective in less than thirty (30) days after the date of publication in the Federal Register.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, § 39.13 of the Federal Aviation Regulations (14 CFR 39.13) is amended by adding the following new Airworthiness Directive.

Cessna: Applies to:

Model 205 (210-5) Series (Serial Numbers 641, 205-0001 through 205-0577) airplanes;

Model 206 (Serial Numbers 206-0001 through 206-0275) airplanes;

Model U206/TU206 Series (Serial Numbers U206-0276 through U206-1444, U20601445 through U20604287, U20604289, U20604290, U20604292 through U20604335, U20604337 through U20604389, U20604391 through U20604787, U20604789 through U20604894, U20604896 through U20604906, U20604908 through U20604911, U20604913 through U20604958, U20604960 through U20604963, U20604965 through U20604973, U20604975 through U20604977, U20604980 through U20604985, U20604987 through U20604990, U20604992, U20604993, U20604995 through U20604998, U20605000 through U20605018, U20605020 through U20605058, U20605060, U20605061, U20605063, U20605066, U20605069,U20605071 through U20605073, U20605075, U20605077, U20605078, U20605083, U20605085, U20605086, U20605088, U20605095, U20605097, U20605100, U20605102, U20605105, U20605107 and U20605110) airplanes;

Model P206/TP206 Series (Serial Numbers P206-0001 through P206-0603, P20600604 through P20600647) airplanes;

Model 207/T207 Series (Serial Numbers 20700001 through 20700530) airplanes;

Model T210 Series (Serial Numbers T210-0001 through T210-0454) airplanes;

Model 210/T210 Series (Serial Numbers 21057841 through 21063013, 21063015 through 21063086, 21063088 through 21063228, 21063230 through 21063287, 21063289 through 21063298, 21063300 through 21063324, 21063326 through 21063389 21063391 through 21063393, 21063396 through 21063399, 21063401, 21063403 through 21063407, 21063412, 21063413, 21063419, 21063424 and 21063426) airplanes;

Model P210 Series (Serial Numbers P21000001 through P21000255, P21000257 through P21000273, P21000275 through P21000279, P21000281 through P21000283, P21000287, P21000290 and P21000292) airplanes.

Compliance: Required as indicated unless already accomplished.

To provide instructions for recognition of fuel system vapor blockage and operating procedures to restore normal fuel flow, within the next 25 hours time-in-service after the effective date of this AD, accomplish the following:

(A) On Model 205 (210-5) series (Serial Numbers 641, 205-0001 through 205-0555); Model 206 (Serial Numbers 206-0001 through 206-0137); Model 210 (Serial Numbers

21057841 through 21058351) airplanes, examine the airplane and its maintenance record to determine whether Cessna Service Kit SK 205-5 or SK 206-2 has been installed. If neither of these kits is installed, make an entry in the maintenance records indicating this AD is not applicable to the airplane and no further action is required. If Cessna Service Kit SK 205-5 or SK 206-2 has been installed, accomplish Paragraphs (B) 1 and 2 of this AD.

(B) On affected (see Applicability Statement) Model 205 (210-5) series airplanes having serial numbers between 205-0556 through 205-0577 inclusive, Model 206 series airplanes having serial numbers between 206-0138 through 206-0275 inclusive, Model U206/TU206 series airplanes having serial numbers between U206-0276 through U206-1444 inclusive and U20601445 through U20604649 inclusive, Model P206/TP206 series airplanes having serial numbers between P206-0001 through P206-0603 inclusive and P20600604 through P20600647 inclusive, Model 207/T207 series airplanes having serial numbers between 20700001 through 20700482 inclusive, Model 210/T210 series airplanes having serial numbers between 21058352 through 21062954 inclusive, Model T210 series airplanes having serial numbers between T210-0001 through T210-0454 inclusive and Model P210 series airplanes having serial numbers between P21000001 through P21000150 inclusive;

1. Install Cessna P/N 1205252-2 placard next to the fuel flow indicator which reads as follows:

"Major fuel flow fluctuations/power surges:

1. Aux fuel pump—ON, adjust mixture.
2. Select opposite tank.
3. When fuel flow steady, resume normal operations. See procedure card D1189-13 for expanded instructions."

2. Place Cessna special procedure card P/N D1189-13 in the airplane at a location accessible to the pilot at all times when he is in the pilot's seat and revise the aircraft Equipment List by adding this card as a required item of equipment.

(C) On affected (See Applicability Statement) Model U206/TU206 series airplanes having serial numbers between U20604650 and U20605110 inclusive, Model 207/T207 series airplanes having Serial Numbers between 20700483 through 20700530 inclusive, Model 210/T210 series airplanes having Serial Numbers between 21062955 through 21063426 inclusive and Model P210 series airplanes having Serial Numbers between P21000151 through P21000292 inclusive;

1. Install Cessna P/N 1205252-1 placard next to the fuel flow indicator which reads as follows:

"Major fuel flow fluctuations/power surges:

1. Aux fuel pump—ON, adjust mixture.
2. Select opposite tank.
3. When fuel flow steady, resume normal operations. See P.O.H. for expanded instructions."

2. Revise the Pilot's Operating Handbook for the following airplanes by inserting the revision specified below:

Airplane model	Revision	Cessna part number
U206G	Rev 1 22 May 1979	D1147R1-13PH
TU206G	Rev 2 22 May 1979	D1148R2-13PH
207A	Rev 1 22 May 1979	D1149R1-13PH
T207A	Rev 2 22 May 1979	D1150R2-13PH
210N	Rev 3 22 May 1979	D1151R3-13PH
T210N	Rev 3 22 May 1979	D1152R3-13PH
P210N	Rev 3 22 May 1979	D1153R3-13PH

(D) The modification required by this AD may be accomplished by owner/operator authorized to perform preventive maintenance under FAR 43. An entry should be made in the aircraft maintenance record indicating compliance; i.e., "AD 79-15-1 complied with by installing placard P/N 1205252-2 and Special Procedure Card P/N D1189-13 this date ———" or "AD 79-15-1 complied with by installing placard P/N 1205252-1 and Pilot's Operating Handbook Rev ——— dated ———, Cessna P/N ——— this date ———."

(E) Airplanes may be flown in accordance with FAR 21.197 to a location where this AD may be accomplished.

(F) Any equivalent method of compliance with this Airworthiness Directive must be approved by the Chief, Engineering and Manufacturing Branch, Federal Aviation Administration, Central Region, 601 E. 12th Street, Kansas City, Missouri 64106.

Cessna Service Letter SE 79-25, dated April 30, 1979, and Supplement No. 1 thereto dated June 4, 1979, pertains to the subject matter of this Airworthiness Directive. Cessna Aircraft Company has mailed copies to all owners of record. Additional copies may be obtained from: Cessna Aircraft Co., Marketing Division, Attn: Customer Service Department, Wichita, Kansas 67201; Telephone (316) 689-9111.

This Amendment becomes effective July 26, 1979.

(Secs. 313(a), 601 and 603, Federal Aviation Act of 1958, as amended, (49 U.S.C. 1354(a), 1421, and 1423); sec. 6(c), Department of Transportation Act (49 U.S.C. 1655(c)); and sec. 11.89 of the Federal Aviation Regulations (14 CFR 11.89))

Note: The FAA has determined that this document involves a regulation which is not significant under Executive Order 12044, as implemented by Department of Transportation Regulatory Policies and Procedures (44 FR 11034; February 26, 1979). A copy of the final evaluation prepared for this document is contained in the docket. A copy of it may be obtained by writing to Donald L. Page, Aerospace Engineer, Engineering and Manufacturing Branch, FAA, Central Region, 601 East 12th Street, Kansas City, Missouri 64106; telephone (816) 374-3446.

Issued in Kansas City, Missouri on July 9, 1979.

John E. Shaw,

Acting Director, Central Region.

[FR Doc. 79-22676 Filed 7-20-79; 8:45 am]

BILLING CODE 4910-13-M

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Social Security Administration

20 CFR Part 404

[Reg. No. 4]

Federal Old-Age, Survivors, and Disability Insurance; Totalization Agreements and International Totalization Agreements

AGENCY: Social Security Administration, HEW.

ACTION: Final Rule.

SUMMARY: These final regulations implement section 317 of the Social Security Amendments of 1977. This provision authorizes the President to enter into bilateral agreements with other countries to provide for coordination between the social security systems of the United States (U.S.) and of other countries. The bilateral agreements are generally known as totalization agreements. The purposes of a totalization agreement are (1) to permit each country to establish entitlement to and the amount of old-age, survivors, disability, or derivative benefits by combining a person's periods of coverage under the social security systems of both countries, and (2) to preclude dual coverage and dual social security taxation for work covered under both systems.

DATES: The final rule is effective July 23, 1979.

FOR FURTHER INFORMATION CONTACT: John W. Modler, Legal Assistant, 6401 Security Boulevard, Baltimore, Maryland 21235, telephone (301) 594-7337.

SUPPLEMENTARY INFORMATION:

A. Background

On December 27, 1978, we published a proposed rule in the Federal Register (43 FR 60292) which adds Subpart T to 20 CFR Part 404. The rule implements the international agreements provisions of the Social Security Amendments of 1977 (Pub. L. 95-216). By adding section 233 to the Social Security Act, section 317 in Pub. L. 95-216 provides the President with the authority for entering into agreements with other countries to provide for coordination between the social security systems of the U.S. and of other countries.

B. Explanation of Provisions

These regulations provide definitions and principles for the negotiation and administration of totalization agreements. These principles cover (1) general provisions, (2) benefits, (3) coverage, (4) computations, (5) applications, (6) evidence, (7) appeals, (8) effect of the alien non-payment provision, (9) overpayments, and (10) disclosure of information.

While these definitions and principles are intended to ensure consistent and equitable treatment of all individuals affected by the agreements, they will necessarily apply to foreign social security systems with diverse characteristics. We will, where necessary to accomplish the purposes of totalization, apply these definitions and principles, as appropriate and within the limits of the law, to accommodate the diverse characteristics of these systems.

1. General Provisions

An agreement will be negotiated with the national government of the foreign country for the entire country. However, agreements may only be negotiated with foreign countries that have a social security system of general application in effect. We will consider a system in effect if it is collecting social security taxes or paying social security benefits.

An agreement may provide that the provisions of the social security system of each country will apply equally to the nationals of both countries (regardless of where they reside). For this purpose, refugees, stateless persons, and other nonnationals who derive benefit rights from nationals, refugees, or stateless persons may be treated as nationals if they reside within one of the countries.

An agreement will become effective on any date, provided in the agreement, which occurs after the expiration of a period specified in section 233(e) of the Act. This period begins when the President transmits the agreement to the Congress and ends when each House of Congress has been in session thereafter on each of 90 days. The agreement will become effective unless one of the Houses of Congress adopts a resolution of disapproval within the 90-day period.

Each agreement will contain provisions for its possible termination. If an agreement is terminated, rights regarding entitlement to benefits and coverage acquired by an individual before termination shall be retained. The agreement will provide for notification of termination to the other party and the effective date of termination.

Provisions on amendments of totalization agreements are not included in these regulations. If we find that regulations are necessary, we will publish them at a later date.

2. Benefits

As a result of a totalization agreement, a person who has at least 6 quarters of coverage (QCs) (see §§ 404.103 and 404.103a) under the U.S. system may have foreign periods of coverage combined with U.S. coverage to determine entitlement to and the amount of benefits payable under the U.S. system. No credit will be given, however, for foreign periods of coverage acquired before January 1, 1937.

Generally, a person will be credited with a QC for every 3 months (or equivalent period), or remaining fraction of 3 months, of coverage in each reporting period certified by the foreign system. A reporting period used by a foreign country may be one calendar year or some other period of time. QCs based on foreign periods of coverage may be credited only to calendar quarters not already QCs under the U.S. system. The QCs will be assigned chronologically beginning with the first calendar quarter (not already a QC under the U.S. system) within the reporting period and continuing until all the QCs are assigned, or the reporting period ends. An example illustrating this provision is provided in § 404.1908(b)(1).

A person may fail to meet the requirements for a currently insured status or the insured status needed to establish a period of disability solely because of the assignment of QCs based on foreign coverage to calendar quarters on a chronological basis. If this occurs, the QCs based on foreign coverage may be assigned to different calendar quarters (not already QCs under the U.S. system) within the beginning and ending dates of the reporting period certified by the foreign country.

An agreement will not provide for combining periods of coverage under more than two social security systems. A person, however, may qualify for benefits under more than one agreement. If this occurs, the person will receive benefits only under the agreement affording the most favorable treatment. In the absence of evidence to the contrary, the agreement that provides the higher benefit will be considered as affording the most favorable treatment.

A person may not become entitled to hospital insurance benefits under section 226 or section 226A of the Social Security Act by combining periods of coverage under the U.S. system with those under the foreign system. Entitlement to hospital insurance benefits is not precluded if the person otherwise meets the requirements.

3. Coverage

An agreement will contain provisions precluding dual coverage. Employment or self-employment (or service recognized as equivalent under the U.S. system or the foreign system) will, on or after the effective date of the agreement, result in a period of coverage under either the U.S. or foreign system, but not under both. Methods will be described in the agreement for determining under which system the service will result in a period of coverage.

Although an agreement may modify coverage provisions of title II of the Act, it should do so by exemptions from coverage rather than by extensions of coverage under title II. Generally, a worker will be covered by the country in which he or she is working. However, an agreement may provide exceptions to this principle so that a worker will be covered by the country to which he or she has the greater attachment. Examples illustrating this principle are provided in §§ 404.1913(b)(3) and 404.1913(b)(4).

Agreements may provide for variations from the general principles for precluding dual coverage to avoid inequitable or anomalous coverage situations for certain workers. However, in all cases coverage must be provided by one of the countries.

An agreement will contain provisions precluding dual payment of contributions or taxes. On or after the effective date of an agreement, any employment or self-employment (or service recognized as equivalent under the U.S. social security system or the foreign system) which is covered under the agreement will be subject to taxes or contributions under the U.S. system or the foreign system, but not under both (see section 317(b) of Pub. L. 95-216).

4. Computations

An agreement will contain a provision regarding the method of computing the benefits payable under the U.S. system if entitlement is established based on combined periods of coverage under the U.S. system and under the foreign system. The benefit payable under the U.S. system will be based on the proportion of the person's periods of coverage credited under the U.S. system.

To determine the benefit payable under an agreement, a "theoretical" primary insurance amount (PIA) will be computed like other title II PIA's, but by combining the person's earnings amounts under both the U.S. and the foreign systems (see § 404.203(a) for the definition of the PIA). Earnings amounts certified by the foreign agency may be actual earnings amounts or deemed earnings amounts derived, for example, from amounts of contributions to the foreign system or from the national average wage under the foreign system. Foreign earnings will be added to any covered U.S. earnings only to the extent that the combined earnings do not exceed the maximum annual earnings limitation under U.S. law (see § 404.1027). Foreign earnings may be assigned to a calendar quarter only if that quarter is a QC based on foreign coverage (see § 404.1908 on crediting foreign periods of coverage). A pro rata PIA will then be derived from the theoretical PIA. The pro rata PIA is the product of (1) the theoretical PIA and (2) the ratio of (a) the periods of coverage credited under the U.S. system to (b) the combined periods of coverage credited under both the U.S. system and the foreign system. In deriving the pro rata PIA from the theoretical PIA, periods of coverage after the last computation base year, as defined in § 404.203(e), will not be considered. An example illustrating this provision is provided in § 404.1918(a).

Auxiliary and survivors benefit amounts will be determined on the basis of the pro rata PIA. The regular reductions for age under section 202(q) of the Act will apply to the pro rata benefits of the wage earner and to any auxiliaries or survivors. Benefits will be payable subject to the family maximum (see § 404.403) derived from the pro rata PIA. If the pro rata PIA is less than the minimum PIA, the family maximum will be 1½ times the pro rata PIA.

The pro rate PIA will be recomputed only if the inclusion of the additional earnings will result in an increase in both the theoretical PIA and the benefits payable by the U.S. to all persons receiving benefits on the basis of the worker's earnings, unless otherwise provided by the agreement. Subject to these limitations, the pro rata PIA will be automatically recomputed, as provided in § 404.244, to include additional earnings under the U.S. system. An application, however, must be filed to have the pro rata PIA recomputed to include additional foreign earnings.

A U.S. resident may receive benefits under an agreement from both the U.S. and from the foreign country. The total amount of the resident's two benefits, however, may be less than the amount for which the resident would qualify under the U.S. system based on the minimum PIA. A totalization agreement may provide that the U.S. will supplement the total amount to raise it to the amount for which the resident would have qualified under the U.S. system based on the minimum PIA.

5. Applications

We will consider an application (or a written statement requesting benefits) filed with the foreign system to be filed with the Social Security Administration (SSA) as of the date it is filed with the foreign system if certain requirements are met. First, an applicant must express or imply an intent to claim benefits from the U.S. under an agreement. Second, the applicant must file an application that meets the requirements in Subpart G of Regulations No. 4, even if the filing of this application is not specifically provided for in the agreement. Benefits will not be payable on the basis of an application filed before the effective date of the agreement.

6. Evidence

SSA shall consider evidence submitted to the social security system of the foreign country as evidence submitted to SSA. SSA will use the rules in §§ 404.708 and 404.709, which were published as a final rule in the Federal Register on June 7, 1978 (43 FR 24794), to determine if the evidence submitted is sufficient or if additional evidence is needed to prove initial or continuing entitlement to benefits.

If an application is filed for disability insurance benefits, SSA will consider medical evidence, if any, submitted to the foreign system as if it were submitted to the U.S. system. We will use the rules in Subpart P of Regulations No. 4, for making a disability determination.

7. Appeals

SSA will consider a request for reconsideration, hearing, or Appeals Council review of a determination made by SSA that is filed with the foreign system within the 60-day time period applicable for these requests to be timely filed with SSA. We will apply the provisions in Subpart J of Regulations No. 4 in adjudicating the request.

8. Effect of the Alien Non-Payment Provision

An agreement may provide that a person entitled to benefits under the U.S. system may receive those benefits while residing in the foreign country party to an agreement, regardless of the alien non-payment provision (see § 404.460).

9. Overpayments

Section 204 of the Act, § 404.502 of the regulations, provides for adjusting payments if a person has received more than the correct payment under title II. Payments made by a foreign country, however, are not considered payments under title II. Therefore, title II benefits may not be adjusted under section 204 of the Act to recover an overpayment made by the foreign system of a country party to a totalization agreement. Section 233 of the Act provides that an "agreement may contain other provisions which are not inconsistent with other provisions of this title* * *" If an agreement authorized the adjustment of title II benefits to recover an overpayment made by the foreign country, the provisions would be "inconsistent with" sections 205(i) and 207 of the Act. Therefore, a totalization agreement may not authorize the adjustment of title II benefits to recover an overpayment made by the foreign system. Section 404.1929 reflects these adjustment prohibitions.

10. Disclosure of Information

The use of information furnished under an agreement generally will be governed by the national statutes on confidentiality and disclosure of information of the county that has been furnished the information. In negotiating an agreement, consideration should be given to the compatibility of the other country's laws on confidentiality and disclosure with those of the U.S. To the extent possible, information exchanged between the U.S. and the other country should be exclusively for purposes of implementing the agreement and the laws to which the agreement pertains.

C. Existing Agreements

The U.S. signed totalization agreements with Italy in 1973 and with the Federal Republic of Germany in 1976. The Italian agreement has already been through the Congressional review process and became effective on November 1, 1978. The President sent the agreement with the Federal Republic of Germany to Congress on September 21, 1978, but Congress adjourned before the 90-day review period elapsed. Therefore, the President resubmitted the agreement to Congress on February 28, 1979. The agreements entered into with Italy and the Federal Republic of Germany are consistent with these final regulations. As agreements become effective, we will notify the public of their availability in the Federal Register.

D. Discussion of Comments

We received four responses to the proposed rule. One commenter recommended that the proposed rules be adopted as published. Another commenter objected, in principle, to all international agreements. An attorney representing Italian nationals employed in the United States by an Italian employer objected to the manner in which we will determine pro rata title II benefits under the Italian and other agreements. Also, several comments on the proposed regulations were received from an actuary. These comments are addressed below.

1. *Procedure for crediting periods of coverage established by the social security system of a foreign country.*—Two comments were received concerning proposed § 404.1908, which explains the procedure we will use in crediting periods of coverage established under the social security system of a foreign country.

One comment expressed concern that the QCs based on foreign coverage would be assigned to almost any quarter advantageous to the individual—even in different years than when the QCs were earned. We have revised the final regulation to indicate that QCs based on foreign coverage will only be creditied to calendar quarters within the reporting period used by a foreign country. A reporting period may be one calendar year or some other period of time. When certifying periods of foreign coverage to us, foreign countries are generally able to identify the number of months of coverage within their reporting period, but depending upon their reporting system, they may not be able to identify the specific months in which the coverage was earned. Our procedure will be to determine first how many QCs were earned in the reporting period certified by the foreign country using the rule stated in § 404.1908(b)(1). We will then assign the QCs earned in the reporting period on a chronological basis beginning with the first calendar quarter (not already a QC under the U.S. system) within that period and continuing until all the QCs based on foreign coverage are assigned or the reporting period ends. Because some foreign countries may not be able to identify the specific months in the reporting period in which the coverage was earned, § 404.1908(b)(2) provides an alternative method for assigning the QCs in the reporting period, if a person is disadvantaged as a result of the QCs being assigned on a chronological basis.

The other comment on proposed § 404.1908 concerned how we would treat a remaining fraction of 3 months in a reporting period certified by the agency of the other country. For example, if the foreign country certifies that a person worked during the 8-month period of February–September 1961, the person will receive three QCs. We have revised § 404.1908(b)(1) to reflect this procedure.

2. *Precluding dual coverage.*—A commenter noted that proposed § 404.1913(b)(3) was unclear in that it first indicates that work would be covered only by the U.S. and not the foreign country, and then explains that the work would be covered by the foreign country. We have completely revised § 404.1913(b). Paragraph (b)(3) of § 404.1913 explains that, generally, an agreement will provide that a worker will be covered in the country in which he or she is working. Paragraph (b)(4) of § 404.1913 explains that an agreement may provide exceptions to the principle in paragraph (b)(3) of § 404.1913 so that a worker will be covered by the country to which he or she has the greater attachment.

3. *Computation of benefits.*—We received several comments of proposed § 404.1918 concerning the computation of benefits under an agreement.

One commenter recommended that we include a statement explaining that the procedure for converting foreign currency into U.S. dollars will be established in the agreements. We believe, and our experience has shown, that this is a matter more appropriately determined at operational meetings with representatives of the foreign country. As we do not intend to include a provision for this purpose in the agreements, the recommendation of the commenter has not been adopted.

Another commenter felt that the computation of benefits under § 404.1918 was not consistent with Article 8.2 of the Italian agreement. We do not agree with this comment. Article 8.2 relates to insured status and provides that if completion of periods of coverage is a requirement for eligibility for benefits under the laws of either the U.S. or Italy, each State will independently take into account, if necessary to establish eligibility, the periods of coverage completed under the laws of the other State. This provision of the Italian agreement is consistent with § 404.1908 of the regulations. Article 9.2 of the Italian agreement explains how benefits will be prorated. It provides that both the U.S. and Italy will compute a theoretical basic benefit amount (the theoretical PIA in the U.S.) by considering the total periods of coverage completed under the laws of the two States. Then under Article 9.2 each State is to determine the pro rata basic benefit amount (the pro rata PIA in the U.S.) according to the following formula:

$$\frac{\text{Periods of coverage in State A}}{\text{Total periods of coverage in both States}} \times \text{Theoretical basic benefit amount in State A} = \text{Pro rata basic benefit amount in State A}$$

This procedure is the same as the procedure set out in § 404.1918 of the regulations, and we do not agree that it is inconsistent with any of the provisions of the Italian agreement.

Another comment questioned how the pro rata PIA would be determined when there are overlapping QCs in one or more calendar years. It was suggested by the commenter that where there are overlapping QCs, all of them for a particular calendar year be used to determine the pro rata PIA. Because we do not credit a QC based on foreign coverage to a calendar quarter that is already a QC under title II, there are no overlapping QCs. However, in response to this and other comments, we have revised the section to clarify how title II benefits are computed under an agreement.

E. Other Changes

A number of editorial changes were made in the final regulation. These changes are to clarify the provisions. We have also revised § 404.1925 to indicate that an individual seeking benefits under an agreement will always be required to complete an SSA application form that meets the requirements of Subpart G of SSA Regulations No. 4.

Accordingly, we are adopting the proposed rule as revised and set out below.

(Catalog of Federal Domestic Assistance Programs No. 13.802, Social Security—Disability Insurance; No. 13.803, Social Security-Retirement Insurance; and No. 13.805, Social Security-Survivors Insurance)

Dated: June 1, 1979.

Robert P. Bynum,

Acting Commissioner of Social Security.

Approved: July 16, 1979.

Joseph A. Califano, Jr.,

Secretary of Health, Education, and Welfare.

Part 404 of chapter III of Title 20 of the Code of Federal Regulations is amended by adding:

Subpart T to read as follows:

Subpart T—Totalization Agreements

General Provisions

Authority: Sec. 205, 233, and 1102; 53 Stat. 1368, 91 Stat. 1538, and 49 Stat. 647, as amended; (42 U.S.C. 405, 433, 1302)

Subpart T—Totalization Agreements

General Provisions

§ 404.1901 Introduction.

(a) Under section 233 of the Social Security Act, the President may enter into an agreement establishing a totalization arrangement between the social security system of the United States and the social security system of a foreign country. An agreement permits entitlement to and the amount of old-age, survivors, disability, or derivative benefits to be based on a combination of a person's periods of coverage under the social security system of the United States and the social security system of the foreign country. An agreement also provides for the precluding of dual coverage and dual social security taxation for work covered under both systems. An agreement may provide that the provisions of the social security system of each country will apply equally to the nationals of both countries (regardless of where they reside). For this purpose, refugees, stateless persons, and other nonnationals who derive benefit rights from nationals, refugees, or stateless persons may be treated as nationals if they reside within one of the countries.

(b) The regulations in this subpart provide definitions and principles for the negotiation and administration of totalization agreements. Where necessary to accomplish the purposes of totalization, we will apply these definitions and principles, as appropriate and within the limits of the law, to accommodate the widely diverse characteristics of foreign social security systems.

§ 404.1902 Definitions.

For purposes of this subpart—

"Act" means the Social Security Act (42 U.S.C. 301 et. seq.).

"Agency" means the agency responsible for the specific administration of a social security system including responsibility for implementing an agreement; the Social Security Administration (SSA) is the "agency" in the U.S.

"Agreement" means the agreement negotiated to provide coordination between the social security systems of the countries party to the agreement. The term agreement includes any administrative agreements concluded for purposes of administering the agreement.

"Competent authority" means the official with overall responsibility for administration of a country's social security system including applicable laws and international social security agreements; the Secretary of HEW is the "competent authority" in the U.S.

"Period of coverage" means a period of payment of contributions or a period of earnings based on wages for employment or on self-employment income, or any similar period recognized as equivalent under the social security system of the U.S. or under the social security system of the foreign country which is a party to an agreement.

"Residence" or "ordinarily resides," when used in agreements, has the following meaning for the U.S. "Residence" or "ordinarily resides" in a country means that a person has established a home in that country intending to remain there permanently or for an indefinite period of time. Generally, a person will be considered to have established a home in a country if that person assumes certain economic burdens, such as the purchase of a dwelling or establishment of a business, and participates in the social and cultural activities of the community. If residence in a country is established, it may continue even though the person is temporarily absent from that country. Generally, an absence of six months or less will be considered temporary. If an absence is for more than six months, residence in the country will generally be considered to continue only if there is sufficient evidence to establish that the person intends to maintain the residence. Sufficient evidence would include the maintenance of a home or apartment in that country, the departure from the country with a reentry permit, or similar acts. The existence of business or family associations sufficient to warrant the person's return would also be considered.

"Social security system" means a social insurance or pension system which is of general application and which provides for paying periodic benefits, or the actuarial equivalent, because of old-age, death, or disability.

§ 404.1903 Negotiating totalization agreements.

An agreement shall be negotiated with the national government of the foreign country for the entire country. However, agreements may only be negotiated with foreign countries that have a social security system of general application in effect. The system shall be considered to be in effect if it is collecting social security taxes or paying social security benefits.

§ 404.1904 Effective date of a totalization agreement.

A totalization agreement shall become effective on any date provided in the agreement if—

(a) The date occurs after the expiration of a period during which each House of Congress has been in session on each of 90 days following the date on which the agreement is transmitted to Congress by the President; and

(b) Neither House of Congress adopts a resolution of disapproval of the agreement within the 90-day period described in paragraph (a) of this section.

§ 404.1905 Termination of agreements.

Each agreement shall contain provisions for its possible termination. If an agreement is terminated, entitlement to benefits and coverage acquired by an individual before termination shall be retained. The agreement shall provide for notification of termination to the other party and the effective date of termination.

Benefit Provisions

§ 404.1908 Crediting foreign periods of coverage.

(a) *General.* To have foreign periods of coverage combined with U.S. periods of coverage for purposes of determining entitlement to and the amount of benefits payable under title II, an individual must have at least 6 quarters of coverage, as defined in section 213 of the Social Security Act, under the U.S. system. As a rule, SSA will accept foreign coverage information, as certified by the foreign country's agency, unless otherwise specified by the agreement. No credit will be given, however, for periods of coverage acquired before January 1, 1937.

(b) *For quarters of coverage purposes.* (1) Generally, a quarter of coverage (QC) will be credited for every 3 months (or equivalent period), or remaining fraction of 3 months, of coverage in a reporting period certified to SSA by the other country's agency. A reporting period used by a foreign country may be one calendar year or some other period of time. QCs based on foreign periods of coverage may be credited as QCs only to calender quarters not already QCs under title II. The QCs will be assigned chronologically beginning with the first calendar quarter (not already a QC under title II) within the reporting period and continuing until all the QCs are assigned, or the reporting period ends. Example: Country XYZ, which has an annual reporting period, certifies to SSA that a worker has 8 months of coverage in 1975, from January 1 to August 25. The worker has no QCs under title II in that year. Since 8 months divided by 3 months equals 2 QCs with a remainder of 2 months, the U.S. will credit the worker with 3 QCs. The QCs will be credited to the first 3 calendar quarters in 1975.

(2) If an individual fails to meet the requirements for currently insured status or the insured status needed for establishing a period of disability solely because of the assignment of QCs based on foreign coverage to calendar quarters chronologically, the QCs based on foreign coverage may be assigned to different calendar quarters within the beginning and ending dates of the reporting period certified by the foreign country, but only as permitted under paragraph (b)(1) of this section.

§ 404.1910 Person qualifies under more than one totalization agreement.

(a) An agreement may not provide for combining periods of coverage under more than two social security systems.

(b) If a person qualifies under more than one agreement, the person will receive benefits from the U.S. only under the agreement affording the most favorable treatment.

(c) In the absence of evidence to the contrary, the agreement that provides the higher benefit will be considered as affording the most favorable treatment for purposes of paragraph (b) of this section.

§ 404.1911 Effects of a totalization agreement on entitlement to hospital insurance benefits.

A person may not become entitled to hospital insurance benefits under section 226 or section 226A of the Act by combining the person's periods of coverage under the social security system of the United States with the person's periods of coverage under the social security system of the foreign country. Entitlement to hospital insurance benefits is not precluded if the person otherwise meets the requirements.

Coverage Provisions

§ 404.1913 Precluding dual coverage.

(a) *General.* Employment or self-employment or services recognized as equivalent under the Act or the social security system of the foreign country shall, on or after the effective date of the agreement, result in a period of coverage under the U.S. system or under the foreign system, but not under both. Methods shall be set forth in the agreement for determining under which system the employment, self-employment, or other service shall result in a period of coverage.

(b) *Principles for precluding dual coverage.* (1) Although an agreement may modify coverage provisions of title II of the Act, it should do so by exemptions from coverage rather than by extensions of coverage under title II. Therefore, if a person performs services that are not now covered under the U.S. system, an agreement should not provide U.S. coverage of these services.

(2) If the work would otherwise be covered by both countries, an agreement will exempt it from coverage by one of the countries.

(3) Generally, an agreement will provide that a worker will be covered by the country in which he or she is employed and will be exempt from coverage by the other country.

Example: A U.S. national employed in XYZ country by an employer located in the United States will be covered by XYZ country and exempt from U.S. coverage.

(4) An agreement may provide exceptions to the principle stated in paragraph (b)(3) of this section so that a worker will be covered by the country to which he or she has the greater attachment.

Example: A U.S. national sent by his employer located in the United States to work temporarily for that employer in XYZ country will be covered by the United States and will be exempt from coverage by XYZ country.

(5) Generally, if a national of either country resides in one country and has self employment income that is covered by both countries, an agreement will provide that the person will be covered by the country in which he or she resides and will be exempt from coverage by the other country.

(6) Agreements may provide for variations from the general principles for precluding dual coverage to avoid inequitable or anomalous coverage situations for certain workers. However, in all cases coverage must be provided by one of the countries.

§ 404.1914 Certificate of coverage.

Under some agreements, proof of coverage under one social security system may be required before the individual may be exempt from coverage under the other system. Requests for certificates of coverage under the U.S. system may be submitted by the employer, employee, or self-employed individual to SSA.

§ 404.1915 Payment of contributions.

On or after the effective date of the agreement, to the extent that employment or self-employment (or service recognized as equivalent) under the U.S. social security system or foreign system is covered under the agreement, the agreement shall provide that the work or equivalent service be subject to payment of contributions or taxes under only one system (see sections 1401(c), 3101(c), and 3111(c) of the Internal Revenue Code of 1954). The system under which contributions or taxes are to be paid is the system under which there is coverage pursuant to the agreement.

Computation Provisions

§ 404.1918 How benefits are computed.

(a)(1) To determine the benefit payable under an agreement, a theoretical primary insurance amount shall be computed like other title II PIA's, but by combining the person's earnings amounts under both the U.S. and the foreign systems (see § 404.203(a) for the definition of the PIA). Earnings amounts certified by the foreign agency may be actual earnings amounts or deemed earnings amounts derived, for example, from amounts of contributions to the foreign system or from the national average wage under the foreign system. Foreign earnings will be added to any covered U.S. earnings subject to the maximum yearly limitation in U.S. law (see § 404.1027). Earnings under the foreign system may be assigned only to those calendar quarters where a QC has been credited based on foreign coverage (see § 404.1908). A pro rata PIA will then be derived from the theoretical PIA. The pro rata PIA is the product of—

(i) The theoretical PIA; and

(ii) The ratio of the periods of coverage credited under the U.S. system to the combined periods of coverage credited under both the U.S. system and the foreign system.

(2) In determining the ratio described in paragraph (a)(1)(ii) of this section, periods of coverage after the last computation base year, as defined in § 404.203(e), will not be considered.

Example: A person needs 25 QCs to be insured, but has only 5 years of work (20 QCs), under the U.S. system. The person, however, worked under the social security system of a foreign country that is a party to a totalization agreement, and has 10 years of foreign work (40 QCs) combined, as described in § 404.1908, with his or her work under the U.S. system. The combined coverage gives the person insured status. The theoretical PIA is computed on the basis of combined earnings under both the U.S. and foreign systems. This amount is then multiplied by the ratio of (1) the periods of coverage credited under the U.S. system to (2) the combined periods of coverage credited under both the U.S. and foreign systems to derive the pro rata PIA. If the theoretical PIA is $270, the computation shall be as follows:

$270 (Theoretical PIA) × 20 (U.S. QCs/60 (20 U.S. + 40 Foreign QCs = $90 (Pro rata PIA)

(b)(1) If first eligibility or death occurs before 1979, the pro rata PIA, as described in paragraph (a) of this section, may not correspond to a PIA in column IV of the table of benefits contained in (or deemed to be contained in) section 215(a) of the Act, as in effect in December 1978. If this occurs, the pro rata PIA will be rounded—

(i) To the nearest PIA in the table;

(ii) To the higher PIA, if it falls exactly between two PIA's in the table; or

(iii) To the next higher multiple of $.10, if it is not a multiple of $.10 and it is less than the minimum PIA contained in the table (see section 215(g) of the Act).

(2) If first eligibility or death occurs after 1978, the pro rata PIA, as described in paragraph (a) of this section, will be rounded to the next higher multiple of $.10, if it is not a multiple of $.10 (see section 215(g) of the Act).

(c) Auxiliary and survivors benefit amounts (see Subpart D) shall be determined on the basis of the pro rata PIA. The regular reductions for age under section 202(q) of the Act shall apply to the benefits of the worker or to any auxiliaries or survivors which are based on the pro rata PIA. Benefits shall be payable subject to the family maximum (see § 404.403) derived from the pro rata PIA. If the pro rata PIA is less than the minimum PIA, the family maximum shall be 1½ times the pro rata PIA.

§ 404.1919 How benefits are recomputed.

The pro rata PIA shall be recomputed only if the inclusion of the additional earnings results in an increase in both the theoretical PIA and the benefits payable by the U.S. to all persons receiving benefits on the basis of the worker's earnings, unless otherwise provided by the agreement. Subject to these limitations, the pro rata PIA will be automatically recomputed (see § 404.244) to include additional earnings under the U.S. system. An application, however, must be filed to have the pro rata PIA recomputed to include additional earnings under the foreign system.

§ 404.1920 Supplementing the U.S. benefit if the total amount of the combined benefits is less than the U.S. minimum benefit.

If a resident of the U.S. receives benefits under an agreement from both the U.S. and from the foreign country, the total amount of the two benefits may be less than the amount for which the resident would qualify under the U.S. system based on the minimum PIA. An agreement may provide that the U.S. shall supplement the total amount to raise it to the amount for which the resident would have qualified under the U.S. system based on the minimum PIA. (The minimum benefit shall be based on the first figure in column IV in the table in section 215(a) of the Act for a person becoming eligible for the benefit before January 1, 1979, or the primary insurance amount determined under section 215(a)(1)(C)(i)(I) of the Act for a person becoming eligible for the benefit after December 31, 1978.)

§ 404.1921 Benefits of less than $1 due.

If the monthly benefit amount due an individual (or several individuals, e.g., children, where several benefits are combined in one check) as a result of a claim filed under an agreement is less than $1, the benefits may be accumulated until they equal or exceed $5.

Other Provisions

§ 404.1925 Applications.

(a)(1) An application, or written statement requesting benefits, filed with the competent authority or agency of a country with which the U.S. has concluded an agreement shall be considered an application for benefits under title II of the Act as of the date it is filed with the competent authority or agency if—(i) An applicant expresses or implies an intent to claim benefits from the U.S. under an agreement; and

(ii) The applicant files an application that meets the requirements in Subpart G of this part.

(2) The application described in paragraph (a)(1)(ii) of this section must be filed, even if it is not specifically provided for in the agreement.

(b) Benefits under an agreement may not be paid on the basis of an application filed before the effective date of the agreement.

§ 404.1926 Evidence.

(a) An applicant for benefits under an agreement shall submit the evidence needed to establish entitlement, as provided in Subpart H of this part. Special evidence requirements for disability benefits are in Subpart P of this part.

(b) Evidence submitted to the competent authority or agency of a country with which the U.S. has concluded an agreement shall be considered as evidence submitted to SSA. SSA shall use the rules in §§ 404.708 and 404.709 to determine if the evidence submitted is sufficient, or if additional evidence is needed to prove initial or continuing entitlement to benefits.

(c) If an application is filed for disability benefits, SSA shall consider medical evidence submitted to a competent authority or agency, as described in paragraph (b) of this section, and use the rules of Subpart P of this part for making a disability determination.

§ 404.1927 Appeals.

(a) A request for reconsideration, hearing, or Appeals Council review of a determination that is filed with the competent authority or agency of a country with which the U.S. has concluded an agreement, shall be considered to have been timely filed with SSA if it is filed within the 60-day time period provided in §§ 404.911, 404.918, and 404.946.

(b) A request for reconsideration, hearing, or Appeals Council review of a determination made by SSA resulting from a claim filed under an agreement shall be subject to the provisions in Subpart J of this part. The rules governing administrative finality in Subpart J of this part shall also apply.

§ 404.1928 Effect of the alien non-payment provision.

An agreement may provide that a person entitled to benefits under title II of the Social Security Act may receive those benefits while residing in the foreign country party to the agreement, regardless of the alien non-payment provision (see § 404.460).

§ 404.1929 Overpayments.

An agreement may not authorize the adjustment of title II benefits to recover an overpayment made under the social security system of a foreign country (see § 404.501). Where an overpayment is made under the U.S. system, the provisions in Subpart F of this part will apply.

§ 404.1930 Disclosure of information.

The use of information furnished under an agreement generally shall be governed by the national statutes on confidentiality and disclosure of information of the country that has been furnished the information. (The U.S. will be governed by pertinent provisions of the Social Security Act, the Freedom of Information Act, the Privacy Act, the Tax Reform Act, and other related statutes.) In negotiating an agreement, consideration, should be given to the compatibility of the other country's laws on confidentiality and disclosure to those of the U.S. To the extent possible, information exchanged between the U.S. and the foreign country should be used exclusively for purposes of implementing the agreement and the laws to which the agreement pertains.

[FR Doc. 79-22680 Filed 7-20-79; 8:45 am]

BILLING CODE 4110-07-M

DEPARTMENT OF DEFENSE

Corps of Engineers, Department of the Army

33 CFR Part 207

Navigable Waters; Restricted Area, Sabine River, Tex.

AGENCY: U.S. Army Corps of Engineers, DoD.

ACTION: Final rule.

SUMMARY: This rule amends the restricted area in the Sabine River at Orange, Texas by deleting all except an area in the vicinity of Pier No. 10. This action is the result of the disestablishment of the Texas Group, Atlantic Reserve Fleet.

DATE: Effective on July 16, 1979.

FOR FURTHER INFORMATION CONTACT: Mr. Ralph T. Eppard, (202) 693-5070 or write: HQDA, DAEN-CWO-N, Washington, D.C. 20314.

SUPPLEMENTARY INFORMATION: Regulations were promulgated under 33 CFR 207.184 on 29 December 1955 to establish a restricted area in the Sabine River at Orange, Texas, for the Texas Group, Atlantic Reserve Fleet. The Texas Group has been disestablished and the property formerly occupied by that organization is now being used by the Naval and Marine Corps Reserve Center. The only pier under the jurisdiction of the Naval and Marine Corps Reserve Center is Pier 10.

The General Counsel has reviewed this matter and is of the opinion that notice of proposed rulemaking and public procedures thereto are unnecessary since the restricted area was designed to protect Texas Group, Atlantic Reserve Fleet facilities and the only pier remaining under the jurisdiction of the Naval and Marine Corps Reserve and needing the restricted area is Pier 10. The Navy concurs in limiting the restricted area. Accordingly, the restricted areas in the vicinity of piers numbered 1 through 9, 11 and 12 are deleted as set forth below:

§ 207.184 Sabine River at Orange, Tex.; restricted area in vicinity of the Naval and Marine Corps Reserve Center.

(a) The area: The berthing area of the Naval and Marine Corps Reserve Center and the waters adjacent thereto from the mean high tide shoreline to a line drawn parallel to, and 100 feet channelward from lines connecting the pier head of Pier 10 and from a line drawn parallel to, and 200 feet upstream from, Pier 10 to a line drawn parallel to, and 100 feet downstream from Pier 10.

(b) The regulations: (1) No vessel or other craft, except vessels of the United States Government or vessels duly authorized by the Commanding Officer, Naval and Marine Corps Reserve Center, Orange, Texas, shall navigate, anchor, or moor in the restricted area. (2) The regulations of this section shall be enforced by the Commanding Officer, Naval and Marine Corps Reserve Center, Orange, Texas, and such agencies as he may designate.

(40 Stat. 266; 33 U.S.C. 1.)

Note.—The Department of the Army has determined that this document does not contain a major proposal requiring preparation of an Inflation Impact Statement under Executive Order 11821 and OMB Circular A-107.

Date: June 1, 1979.

Michael Blumenfeld,

Assistant Secretary of the Army (Civil Works).

[FR Doc. 79-22602 Filed 7-20-79; 8:45 am]

BILLING CODE 3710-92-M

DEPARTMENT OF TRANSPORTATION

Materials Transportation Bureau

49 CFR Part 192

[Amdt. 192-34; Docket PS-54]

Transportation of Natural and Other Gas by Pipeline; Joining of Plastic Pipe

AGENCY: Materials Transportation Bureau.

ACTION: Final rule.

SUMMARY: This amendment establishes tests for qualifying procedures and personnel to make all types of joints in plastic pipelines used in the transportation of natural and other gas, including heat fusion, solvent cement, adhesive, and mechanical joints. These new requirements are intended to minimize the possibility of joints coming apart and causing gas pipeline failures.

DATES: This amendment becomes effective January 1, 1980. This date gives operators time to assure that joining procedures and persons making joints have been qualified in accordance with this amendment. As further explained in the text, interested persons may submit written comments on certain issues until August 31, 1979.

ADDRESS: Communications should refer to the docket and amendment number and should be sent to: Docket Branch, Materials Transportation Bureau, Department of Transportation, Washington, DC 20590.

FOR FURTHER INFORMATION CONTACT: Paul J. Cory, 202-426-2392.

SUPPLEMENTARY INFORMATION: On October 18, 1978, the Materials Transportation Bureau (MTB) issued a notice of proposed rulemaking regarding the establishment of new safety regulations in Part 192 for qualifying procedures and personnel to make all types of joints used with both thermoplastic and thermosetting plastic pipe, including heat fusion, solvent cement, adhesive, and mechanical joints (43 FR, 49334, October 23, 1978). The deadline for comments was December 15, 1978, and over 95 persons submitted their views on the proposal. Also, the notice was presented to the Technical Pipeline Safety Standards Committee in accordance with Section 4 of the Natural Gas Pipeline Safety Act of 1968 (49 USC 1673). The Committee considered the notice at a meeting in Washington, D.C., on December 5, 1978, but did not make a recommendation on the technical feasibility, reasonableness, and practicability of the proposal.

Following is a discussion of significant comments received and their disposition in reaching a decision on the final rules:

Justification for this Rulemaking

Many comments suggested that the proposal was inappropriate and should be withdrawn because the accidents covered by the National Transportation Safety Board (NTSB) reports cited in the notice would not have occurred if the installation of joints had been made in compliance with existing requirements of Part 192 and fittings had been used as they were designed to be used.

MTB does not agree with this conclusion because compliance with present requirements in Part 192 for joining of plastic pipe will not necessarily ensure that sound joints will be produced; and Part 192 does not contain standards intended to assure that personnel know how to make joints correctly. Specifically, Part 192 does not describe either the characteristics of the burst test to be used in qualifying joining procedures or how test results are to be evaluated in determining whether a joining procedure is effective in meeting the performance objectives for a joint. More important, Part 192 does not require that a joining procedure be qualified from the standpoint of making a joint secure against anticipated pull out forces. Thus, the current standards leave to each operator's judgment the type of testing and proof needed to qualify procedures to make sound joints; and in the absence of a standard test, the use of different test methods can produce different test results on joints made by the same procedures.

One commenter asked that MTB cite the number of individual leak reports under Part 191 that have involved plastic pipe joints. For the seven years of data that is readily available (1970–1976), there are 64 individual written reports of failures submitted pursuant to Section 191.9 that have involved plastic pipe joints. It must be recognized that these reports are only required from distribution operators who have 100,000 or more customers. The accidents at Freemont, NB, and Lawrence, KS, referred to in the notice, and any other such accidents that have occurred in systems with less than 100,000 customers would not be included in that number because no individual written accident reports are required to be submitted from operators of this size.

Cost

The notice proposed that joining procedures and personnel be qualified by subjecting specimen joints to a series of specified burst and tensile tests. Virtually all 95 comments stated that the proposed qualification tests would result in an initial start-up cost in excess of $100 million nationally. Most of this expense would be for new laboratory buildings and equipment to handle numerous and frequent personnel testing. In addition, commenters argued that the annual recurring cost would be high for materials destroyed during testing and for salaries of high level technicians required to conduct the proposed tests. While costs shown by MTB's Evaluation were not as high (because of different assumptions), MTB was persuaded by comments that alternate testing procedures, as adopted in the final rules, could be used effectively to provide the intended level of safety and also reduce the cost to a minimum. A Final Evaluation of the projected costs is included in the docket as required by DOT procedures for improving Government regulations (49 FR 11034). The Evaluation projects a start-up cost of approximately $1,823,000 and an annual cost of approximately $365,000 to the regulated industry.

Qualifying Tests for Procedures

Several comments contended that any test method that demonstrates that joints are as strong as the adjoining pipe in both burst and tensile strength is entirely adequate. This point was discussed in the preamble to the notice in the text. To repeat, MTB believes that in the absence of a standard test to qualify joining procedures, various testing methods used may give inconsistent results that cannot be relied upon to prove the reliability of joints tested.

One commenter stated that there are not enough test facilities in the country to handle the proposed testing. Considering similar comments from others and the large number of persons that join plastic pipe, MTB feels that this view is correct, and the final rules have been changed with this in mind.

Pressure Burst Tests

In the notice, MTB proposed to adopt as a standard burst test the short-time pressure test that is found in ASTM D1599, "Standard Method of Test for Short-Time Rupture Strength of Plastic Pipe, Tubing and Fittings". This test is widely used for quality control during the manufacturing of plastic pipe, and has the advantage of being conducted in only 60 to 90 seconds. Most of the comments received agreed with the intent of the notice to provide standardized testing procedures for each type of plastic pipe joint but stated that the application of the D1599 burst test to mechanical joints was inappropriate for the reasons discussed hereinafter.

Comments also pointed out that although a sustained pressure test conducted under the restrictions set forth in Paragraph 8.6 of ASTM D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing and Fittings" is a much more severe test than the proposed burst test, it should be permitted as an acceptable burst test. This test has been widely used by industry as a reliable test for qualifying joining procedures for making heat fusion, solvent cement, and adhesive joints, and incorporates the test provisions of ASTM D1598 "Standard Method of Test for Time-To-Failure of Plastic Pipe Under Constant Internal Pressure." Under this test, by applying a continuous high stress over a long period of time (1000 hours), even minor flaws are detected in a sample joint, as well as those that would cause a pipeline failure at maximum design stress levels during the life of the pipeline. MTB believes that this test can be relied upon, as many commenters indicated, to determine the acceptability of heat fusion, solvent cement, and adhesive joining procedures, and it deserves recognition in the final rules. As a result, the final rule in Section 192.283 permits compliance with Paragraph 8.6 of ASTM D2513 as one method of performing the required burst test for qualifying procedures used in making heat fusion, solvent cement, and adhesive joints in plastic pipelines.

One commenter stated that the proposed ASTM D1599 test permits leakage at the fitting during testing (Paragraph 8.5).

In reviewing this paragraph, MTB notes that this test is normally used to test sections of pipe. The fittings referred to in this paragraph are those used to provide and closures or connections to the test sample and would not include a fitting being tested.

When a pipe specimen or joining procedures that are being qualified under the proposed D1599 test are intended for use in natural gas piping systems, Paragraph 8.7 of ASTM D2513 modifies the test somewhat by providing that it be performed at a specified minimum fiber stress for each type of materials. Additional requirements were established in D2513 in recognition of the increased hazard involved in the event of a leak of natural gas as compared with other products that may be carried by plastic pipe. Although the minimum fiber stress specified for the short-time D1599 test is much higher than that used under Paragraph 8.6 for the constant internal pressure test (D1598), the short-time test is not as sensitive in detecting minor flaws as a constant internal pressure test. However, MTB believes that the D1599 test will detect the flaws in heat fusion, solvent cement, and adhesive joints that could cause hazardous pipeline failures. For the above reasons, the final rule is changed to require compliance with either Paragraph 8.6 or 8.7 of ASTM D2513 in conducting the required burst test. However, since the use of the D1599 pressure test as modified by Paragraph 8.7 of ASTM D2513 was not addressed in the notice, MTB invites interested persons to submit further written comments on the safety advantages of qualifying heat fusion, solvent cement, and adhesive joining procedures under this test procedure. MTB will consider all comments received by August 31, 1979, with a view toward taking any further necessary action on this matter before the final rule becomes effective.

The proposal to delete the first sentence of § 192.281(a) was reconsidered by MTB in light of comments received on the notice regarding burst testing to qualify a mechanical joining procedure. It can be readily shown from the requirements of Subpart D of Part 192 that the fittings in use for mechanical joints must have burst strength that equals or exceeds that for plastic pipe. A review of the catalogs of various manufacturers of fittings for joining plastic pipe shows that they consistently have a higher burst strength than the plastic pipe being joined. Thus, both the existing and the proposed burst test would cause failure of the plastic pipe before the burst stress of the fittings used to make the mechanical joint is reached. Because of this, the requirement for a burst test for qualifying procedures in making mechanical joints does not appear necessary and is not included in the final rule. However, since this issue also was not addressed in the notice, MTB invites interested persons to submit written comments on the effect on safety caused by the deletion of the requirement for qualifying mechanical joining procedures by burst testing. MTB will consider all comments received by August 31, 1979, with a view toward taking any further necessary action on this matter before the final rule becomes effective.

Tensile Pull Test

MTB proposed that all joining procedures for plastic pipe be qualfied by a longitudinal pull test in addition to a burst test to assure the integrity of joints under pull-out force conditions. The notice proposed the use of a longitudinal pull test that was approved by ASTM on Septemer 2, 1978, as Paragraph EM8.14-Categorization of Mechanical Joints, to be added on an interim basis to ASTM D2513–75b. This test was developed by the ASTM F17.60 Gas Piping Systems Subcommittee specifically for use in determining the capabilities of mechanical joints in plastic-pipe. Comments pointed out that in the case of large diameter pipe, this proposed test would not permit heat fusion, solvent cement, or adhesive joining procedures to be qualified by pull testing longitudinal straps cut from a specimen joint, as is the current industry practice. In making the proposal, MTB did not consider that in testing samples of an entire joint as required by EM 8.14 on pipe sizes of 4 inches and larger diameter, the forces required can reach several hundred-thousand-pounds and require excessively large equipment. Such equipment is very expensive and, although it could be built, few if any such machines are currently available.

MTB evaluated alternative tensile pull tests suggested by commenters and found that ASTM D638, which was referenced in the proposed EM8.14 test, satisfied both the purpose of the proposal and the commenter objections. ASTM D638 includes procedures designed for testing sections of plastic pipe or straps cut from the pipe wall that will readily determine if specimen joints made by heat fusion, solvent cement, or adhesive methods are as strong as the pipe.

In reviewing ASTM D638–77a, MTB finds that it does establish uniform procedures for longitudinal pull testing of both full sections of pipe and tubing as well as straps from such sections. This test is very similar to the pull test proposed in the notice except for the configuration of the specimen. The use of the D638 method with straps taken from large diameter pipe also has the advantage of reducing the forces and the size of the pull testing machine required for large diameter pipe joint samples to lower levels that permit the use of currently available equipment. For these reasons, MTB has adopted in the final rule the requirement that heat fusion, solvent cement, and adhesive joints must meet the requirements of ASTM D638–77a "Standard Test Method for Tensile Properties of Plastics" instead of the tests proposed in the notice.

Commenters pointed out that lateral connections of pipe or fittings to straight pipe sections do not have a configuration that can be subjected to a tensile pull test such as the test proposed in the notice or the one in ASTM D638. Therefore, an alternative method of detecting whether joints at lateral connections have tensile strength equal to or greater than that of the pipe being joined must be used. One method recommended is to subject a specimen of laterally joined pipe to an impact force parallel to the axis of the pipe to which the lateral connection is made until failure occurs in the specimen. If failure occurs outside of the joint area, the joining procedure qualifies for use. Several commenters state that this method will detect unbonded areas and similar voids in the joint area of lateral connections. MTB has witnessed such testing of lateral connections and, as a result, believes this to be an effective method of evaluating such joints. Because of this, the final rule requires such an impact test be used in qualifying joining procedures to make lateral connections. However, since the use of an impact force to test lateral connections was not discussed in the notice, MTB also invites comments on the safety advantages or disadvantages of qualifying joining procedures for lateral connections by heat fusion, solvent cement, and adhesive methods under this test method. MTB will consider all comments received by August 31, 1979, with a view toward taking any further necessary action on this matter before the final rule becomes effective.

Several commenters pointed out that in using the proposed tensile test for mechanical joints, the forces involved in testing a joint to failure of the connecting pipe for 4-inch and larger diameters with present materials are in the order of 1,000,000 to 4,000,000 pounds. This estimate did not include the new higher strength materials or thermosetting materials which would have even higher strength. These forces far exceed any forces that could be anticipated on such pipelines and would also exceed the capacity of the available testing equipment, as was discussed earlier in this preamble. It appears to MTB that a solution to this problem that would provide the intended level of safety and reduce the forces required to test such fittings would be to provide an exception for joints in pipelines 4 inches and larger in diameter from the tensile test requirements of Paragraph EM8.14 of ASTM D2513–75b. This exception would modify the tensile stress required to be equal to or greater than the maximum thermal stresses that would be produced by a temperature change of 100°F. The use of a 100°F temperature differential is based upon the approximate temperatures experienced in above ground service riser tests used in previous rulemaking and the moderating effect of soil cover on the temperature of buried pipelines. Because of the phenomenon of relaxation of stresses that occurs with all plastic materials and the slow temperature changes in underground pipelines, this stress would be at least double the stress that would occur in such pipelines during the operating life.

Commenters also pointed out that there are methods of installation of mechanical joints that protect a joint from being subjected to anticipated longitudinal stresses, such as providing flexibility in the piping, harnessing the joint, or anchoring the pipe. MTB has considered that practice of using installations of this type and is satisfied that they can provide an adequate level of safety and meet the strength requirements for joints of § 192.273(a).

Because of the problems with testing of large diameter mechanical joints and the recognition of the use of various methods available to eliminate the longitudinal forces to which some mechanical joints may be subjected, the final rule requires that joints must be made by a procedure that meets the test requirements of ASTM D2513–75b, Paragraph EM8.14, Categorization of Mechanical Joints, as proposed, except for a procedure that is used to make joints that:

(1) Will not be subject to the design pullout or thrust forces of § 192.273(a); or

(2) Are 4 inches and larger in pipe diameter, the tensile stress used in testing shall equal or exceed the maximum thermal stress that would be produced by a temperature change of 100 degrees F. (55.6 degrees C.).

This discussion has been based upon the tensile pull test procedures in EM8.14 of ASTM D2513–75b and has discussed the excessive forces required to test mechanical joints that are 4 inches and larger in nominal pipe diameter. Because of these problems and the brevity of EM8.14, MTB is including an edited version of these requirements in the text of Section 192.283 rather than adopting by reference.

One comment suggested that MTB list each type of joint that would require different procedures. MTB believes that such a listing is unnecessary since it does not appear that operators have a problem in correctly matching procedures to the joint to be made. Also, if an improper procedure is used to make a joint, this fact should be readily detectable to the person inspecting the joint.

MTB wishes to emphasize that procedures for making joints in plastic pipe may be tested by the pipe or fitting manufacturers, the pipeline operator, or others, but the operator is legally responsible for qualification of the procedures that are to be used to join plastic pipelines.

Qualifying Persons To Make Joints

The notice proposed to require persons making any type of joint in plastic pipe to be qualified by having specimen joints made by such persons subjected to the same tests proposed to qualify joining procedures, that is both tensile test and burst test.

One commenter stated that there was no quick and easily conducted test adaptable for qualifying persons to make sound joints in accordance with the joining procedures. MTB agrees that the tests proposed may not be adaptable for such use, but other comments have suggested that MTB adopt qualification tests that are now being used successfully by some operators to verify the ability of persons to make sound joints in plastic pipe.

Many comments were made stating that the burst test and tensile pull test proposed for qualifying persons to make heat fusion, solvent cement, and adhesive joints were not practical because of the large number of persons making joints, the large number of joining methods, the lack of laboratory facilities, equipment, and staff to do the testing. These same comments pointed out that once the procedures were qualified, strict adherence to those procedures and close visual inspection could be used to determine the capability of persons making joints. In the case of heat fusion, solvent cement, and adhesive joints, a close visual inspection of completed specimen joints and the cut surface sections of those joints along with subjecting the joint sections to destructive strain would readily provide an evaluation of persons making such joints. MTB believes these comments to be correct and analyzed the methods available for evaluating joints in plastic pipe as discussed below.

Heat Fusion, Solvent Cement, and Adhesive Joining

MTB determined the most desirable characteristics to be considered in selecting a test for qualifying persons to make heat fusion, solvent cement, or adhesive joints, and evaluated the various test methods suggested by comments against these criteria.

In order of priority, the desirable characteristics considered by MTB in evaluating these test methods include:

1. Effective in detecting flaws in joints tested.

2. Easily understood by persons being qualified and persons conducting the test.

3. A minimum of special equipment.

4. Quick test results.

5. Low in cost.

For all types of joints in plastic pipelines, the notice proposed the use of the ASTM D1599 short-time burst test and a longitudinal pull test using ASTM D2513–75b, Paragraph EM8.14, Categorization of Mechanical Joints. The ASTM D1599 test is effective as a short-time burst test for detecting flaws affecting the circumferential strength of a joint or pipe segment. The basic principle of the test is readily understood. However, an accurately controlled temperature and pressurizing system capable of applying essentially continuously increasing internal pressure to the test specimen is required. Thus, special equipment is required, and there is a minimum delay of at least one hour for temperature conditioning of the test specimen. The limitations and problems of using the pull test established in EM8.14 of ASTM D2513 has been discussed above. These problems make the proposed test methods excessively costly for the frequent use that would be needed to qualify persons to make joints.

Radiography has been used to examine plastic pipe joints. However, according to the AGA Plastic Pipe Manual—1977, "the adequacy of coverage of a joint is questionable and the equipment is costly." MTB believes that the principle of radiography is commonly understood because of its use for other purposes; but because of the questionable results and high level of skill and training required to perform tests, radiography is not considered acceptable for this purpose.

In discussing ultrasonic testing, the AGA Plastic Pipe Manual—1977 says,

> Another method of nondestructive testing is the use of ultrasonic sound waves to detect flaws or imperfections in the joint. Although moderately costly, several companies have found this method very reliable when used by trained operators. The technique is fast and accurate.

In addition, papers presented at the Institute of Gas Technology, Symposium on Nondestructive Testing of Pipe Systems, June 7–10, 1976, and at the AGA Distribution Conference, May 7–9, 1979, demonstrate that ultrasonic testing is very effective in evaluating the quality of heat fusion, solvent cement, or adhesive joints, provided inspectors are properly trained. In the opinion of MTB, the equipment needed is both complicated and expensive and requires a high level of skill. Thus, MTB does not believe that ultrasonic testing meets the criteria above.

Visual examination of the exterior of a completed heat fusion, solvent cement, or adhesive joint by examining the entire circumference of the joint area is the most common method of determining joint quality. By comparing the appearance of a joint being inspected with the appearance of a joint that is known to be satisfactory, visible faults can be readily detected. This method is easily understood, requires little special equipment, gives quick results, is low in cost and reasonably effective in detecting flaws. Thus, MTB believes visual examination of the completed joint meets the criteria listed above.

If a specimen joint that has passed a visual examination, as described above, is then cut into straps longitudinally across the joint area, the cut surfaces of the joint area can be visually examined to detect any voids or unbonded areas that may not have been readily detectable by the visual inspection of the full joint as described in the paragraph above. This method is also easily understood, requires a minimum of equipment, gives quick results, is low in cost, and is more effective in detecting flaws in joints than visual inspection of the completed joint.

Another method that is often used is to subject straps like those cut in the method described in the previous paragraph to destructive strain. This strain may be applied by any method, but is usually induced by tensile pull, bending, torque, or impact. If the resulting fracture occurs in the joint, the joint is not acceptable. This method is also effective in detecting flaws, is easily understood, requires a minimum of equipment, gives quick results, is low in cost, and meets all of the criteria listed by MTB.

Several comments described a method that combines the three preceding test methods. These commenters indicated that such a combined testing procedure is very effective in evaluating the skill of a person to make joints in plastic pipe. MTB has witnessed similar tests and believes such procedures to be highly reliable for evaluating a specimen joint. Such a combined test meets all of the desirable characteristics listed. Because of this, the final rule requires a person being qualified under a joining procedure to make a joint in accordance with that procedure. The completed joint must have the same appearance as a sample joint or photographs of a sample joint that has been found acceptable under the applicable procedure qualified in accordance with § 192.283; and in the case of a heat fusion, solvent cement, or adhesive joint, cut into at least 3 longitudinal straps, each of which is visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area. Each strap must then be destructively tested and found not to have failed in the joint area. The destructive testing may be done by any appropriate method, such as tensile pull, bending, torsion or impact.

Mechanical Joints

Many comments stated that for mechanical joints, once a joining procedure has been shown to meet the requirements of the proposed qualification tensile test, the joining procedures are so simple that persons making joints should only need to show that they have followed the procedures to be qualified. MTB has reviewed the joining procedures for various mechanical joints and has found that they are consistently simple and straightforward and do not require a high level of skill to implement. As a result of these findings, the final rule for qualifying persons to make sound mechanical joints requires the person to be qualified by training or experience in the use of the joining procedure, and to make a specimen joint from pipe sections joined according to the procedure that is visually examined and found to have the same appearance as a specimen joint or photographs of a specimen joint that meets the applicable test requirements of § 192.283. Further, physical testing of the joint is not required.

Longitudinal Stress

Longitudinal forces resulting from thermal changes and external forces covered by the requirements of § 192.273(a) have been a factor in various plastic pipeline failures. If joining procedures that have been qualified under § 192.283 are followed in making joints, with consideration being given to anticipated thermal and external forces, the resulting joints will be able to withstand the thermal stresses that can be anticipated and will minimize the probability of similar failures occurring on pipelines constructed in the future.

One comment pointed out that there are locations where a mechanical joint with less resistance to longitudinal forces than other joints is used to provide a preferred location for a failure, should one occur. Using the test required for qualifying joining procedures for mechanical joints (§ 192.283(b)), such an installation could be made by designing other joints on the pipeline segment to exceed the requirements of § 192.273(a) and designing the joint in question to just meet those requirements. This would mean that an unanticipated force in excess of design would cause failure at the less hazardous, preferred location selected by the operator.

Requalification

There were several comments stating that although some operators may wish to qualify some of the persons making joints annually, as proposed, such a requirement would in many cases be an excessive restriction that did not relate to the proficiency of the person to make joints. One commenter suggested that an annual requalification of such persons was not adequate because it did not relate to the quality of the joints produced and that the need for requalification should be based upon the frequency that an individual made field joints that were found to be unsatisfactory by the required joint inspection. MTB agrees with this concept as being a better performance approach to the problem than was proposed and has, therefore, revised the proposed requirement for annual requalification of persons to make joints in plastic pipe with a prohibition under § 192.285(b) that no person who has made three or more joints found to be unacceptable under a particular joining procedure within any 12-month period may make joints under that procedure until that person is requalified under § 192.285(a)(2).

A comment suggested making requirements for qualifying persons to make plastic pipe joints similar to those for welded joints on steel pipe in API 1104, Section 3.2 Multiple Qualifications. This would require retraining annually and testing of one joint by nondestructive testing. MTB believes this suggestion to be impractical as a Federal requirement in that the most effective nondestructive test for use on plastic pipe would be ultrasonic inspection, and there are difficulties with this method as discussed above. In addition, adequate, less complicated and less costly inspection and testing methods can provide an acceptable level of safety.

Training

Under the new §§ 192.285 and 192.287, persons who make joints in plastic pipelines and persons who inspect joints in plastic pipelines must be qualified by appropriate training or experience in the joining procedures being used. All comments agreed with this proposal in the notice.

Because of the wide variations in materials and operating conditions, MTB does not believe it has enough information to establish specific requirements concerning the material to be included in the required training. Operators may develop their own training programs or use other relevant training materials in any manner that is best suited to their situation. Training material that may be useful for this program is available from various pipe and fittings manufacturers and industry organizations, such as the American Gas Association, American Society of Mechanical Engineers, and Plastic Pipe Institute.

Certificate of Qualification

Most commenters objected to § 192.283(b)(3) in the notice, which would have required each person joining plastic pipe to have in his possession a certificate signed by the operator stating that the requirements for testing and training or experience have been met. Several comments pointed out that this would involve excessive amounts of recordkeeping that would be redundant. MTB is convinced that to assure that only qualified persons make joints in plastic pipelines, there should be some method to establish that a person making joints in plastic pipe has been qualified in accordance with § 192.285. A certificate issued to the person making joints is one method to do this, but other methods may be just as effective. In the final rule, each operator of plastic pipelines is required to establish a method to determine that each person making plastic pipe joints in his system is qualified. The rule leaves the operator free to establish a method best suited to his operations. Accordingly, the certificate requirement proposed in the notice has not been adopted in the final rule.

Inspection of Joints

Several comments indicated that they agreed with the proposed "training or experience" requirement for persons who inspect joints in plastic pipelines, provided it was intended that inspection could be done by the person making the joint. This was not the intent of the proposal inasmuch as the actual inspection requirement is stated under § 192.273(c). However, MTB believes that it is axiomatic that an adequate inspection of a job cannot be done by the person who has performed the job.

One commenter pointed out that to assure that correct procedures are used to make joints, a copy of the procedures intended to be used should be available to the persons making and inspecting joints at each joining site. MTB believes this would contribute to improving the quality of joints in plastic pipelines with negligible costs and has, therefore, included this in the final rule.

In consideration of the foregoing, Part 192 of Title 49 of the Code of Federal Regulations is amended as follows:

§ 192.81 [Amended]

1. By deleting the first sentence of § 192.281(a).

2. By adding a new § 192.283 to read as follows:

§ 192.283 Plastic pipe; qualifying joining procedures.

(a) *Heat Fusion, Solvent Cement, and Adhesive Joints.* Before any written procedure established under § 192.273(b) can be used for making joints in plastic pipe by a heat fusion, solvent cement, or adhesive method, it must be qualified by—

(1) Meeting the burst test requirements of Paragraph 8.6 (Sustained Pressure Test) of Paragraph 8.7 (Minimum Hydrostatic Burst Pressure) of ASTM D2513; and

(2) Meeting the tensile test requirements of ASTM D638 or, in the case of a procedure for making lateral connections to pipelines, by subjecting a specimen made from pipe sections joined at right angles according to the procedures to an impact force on the lateral pipe parallel to the axis of the pipe to which the lateral connection is made until failure occurs in the specimen. In this latter test, if failure occurs outside the joint area, the procedure qualifies for use.

(b) *Mechanical Joints.* Except for a procedure applicable to joints that will not be subjected to the design pullout or thrust forces addressed in § 192.273(a), before any written procedure established under § 192.273(b) can be used for making joints in plastic pipelines by a mechanical method, it must be qualified in accordance with the following test for determining short-term pullout resistance:

(1) The apparatus and conditioning for the testing shall be as specified in ASTM D638–77a.

(2) The speed of the testing shall be 5.0 mm (0.20 inches) per minute, plus or minus 25 percent.

(3) Five specimen joints shall be prepared following the procedure being qualified. Length of the specimen shall be such that the distance between the grips of the apparatus and the end of the stiffener is at least five times the nominal outside diameter of the pipe size being tested.

(4) Pipe specimen less than 4 inches in diameter shall be pulled until the tubing yields to an elongation of 25 percent or is pulled from the fitting. Length of yield is to be ascertained over a 50 mm (2 inch) span.

(5) Pipe specimen 4 inches and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100° F (55.6° C).

(6) Specimen that fails at the grips shall be retested using new pipe or tubing.

(7) If the pipe or tubing pulls from the fitting, the lowest of the five values shall be used in the design calculations for stress.

(8) Results obtained pertain only to the specific outside diameter, wall thickness, and material of the pipe or tubing tested.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints at the site where joining is accomplished.

3. By adding new § 192.285 to read as follows:

§ 192.285 Plastic pipe; qualifying persons to make joints.

(a) No person may make a joint in a plastic pipe unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure, that is—

(i) Visually examined and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(ii) In the case of a heat fusion, solvent cement, or adhesive joint, cut into at least 3 longitudinal straps, each of which is—

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Destructively tested and found not to have failed in the joint area.

(b) No person determined to have made three or more unacceptable joints under an applicable joining procedure within any 12-month period may be considered qualified under that procedure in accordance with Paragraph (a) of this section until that person has been requalified under Paragraph (a)(2) of this section.

(c) Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section.

4. By adding a new § 192.287 to read as follows:

§ 192.287 Plastic pipe; inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by §§ 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

5. In Section II of Appendix A, by redesignating items (19) and (20) as items (20) and (21), respectively, and adding a new item (19) as follows:

Appendix A—Incorporated by Reference

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(19) ASTM Specification D638 "Standard Test Method for Tensile Properties of Plastic" (D638–77a)

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6. By amending the Table of Contents Part 192 to include the following new sections.

Subpart F—Joining of Materials Other Than by Welding

* * * * *

§ 192.283 Plastic pipe; qualifying joining procedures.
§ 192.285 Plastic pipe; qualifying persons to make joints.
§ 192.287 Plastic pipe; inspection of joints.

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(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR 1.53 and App. A of Part 1)

Issued in Washington, D.C., on July 9, 1979.

L. D. Santman,

Director, Materials Transportation Bureau.

Note.—Incorporation by reference provisions approved by the Director of the Federal Register July 17, 1979.

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Federal Railroad Administration

49 CFR Part 265

[Docket No. 79-905]

Nondiscrimination in Federally Assisted Railroad Programs; Correction

AGENCY: Federal Railroad Administration (FRA), Department of Transportation.

ACTION: Correction of Background Statement.

SUMMARY: On June 21, 1979, FRA published amendments to 49 CFR Part 265, modifying the definition of minority business enterprise (MBE) and providing guidance in establishing the eligibility of MBEs (44 FR 36338). The background statement to the amendments contained an incorrect summary statement of an investigation report. The corrected summary statement is contained herein.

FOR FURTHER INFORMATION CONTACT:

Principal Authors

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Principal Policy Person: Miles Washington, Minority Business Resource Center, Federal Railroad Administration, 400 Seventh Street, SW., Washington, D.C. 20590, (202) 426-2852.

SUPPLEMENTARY INFORMATION: On June 21, 1979, FRA published amendments to 49 CFR Part 265, modifying the definition of minority business enterprise (MBE) and providing guidance in establishing the eligibility of MBEs (44 FR 36338). The background statement to the amendments contained the following statement:

"The Minority Business Resource Center, in investigating the procurement practices of the Chicago area railroads subject to Part 265, found that these railroads were awarding approximately 80 percent of their MBE awards to businesses for which ownership had been transferred but control retained by non-minority persons. Many of such firms had prior contractual relationships with these railroads on a non-MBE basis. Clearly the intent of Part 265 had been subverted."

The investigation referenced in the quoted language did reveal that a number of firms doing business with one or more of the railroads had acquired MBE eligibility status by transferring fifty percent (50%) of the stock ownership from husband to wife. It has been brought to FRA's attention that the investigation report does not support the conclusion that the problem has reached proportions stated in the quoted language. We agree. The quoted language should have read as follows:

"The Minority Resource Center, in investigating the procurement practices of the Chicago area railroads subject to Part 265, found that the majority of the MBE procurements at each of the railroads inspected were with firms which were fifty percent (50%) owned by women. The investigation also revealed that some white male-owned and traditional suppliers to railroads had transferred stock to their wives and the firms thereafter claimed MBE status. Thus, the affirmative action goals of the regulations were not being achieved."

Issued in Washington, D.C., on July 17, 1979.

John M. Sullivan,

Administrator.

[FR Doc. 79-22700 Filed 7-20-79; 8:45 am]

BILLING CODE 4910-06-M

INTERSTATE COMMERCE COMMISSION

49 CFR Part 1033

[S.O. 1316, Amdt. 5]

Chicago and North Western Transportation Co. Authorized To Operate Over Tracks of Chicago, Milwaukee, St. Paul and Pacific Railroad Co. at Appleton, Wisconsin

AGENCY: Interstate Commerce Commission.

ACTION: Emergency Order. Amendment No. 5 to Service Order No. 1316.

SUMMARY: Service Order No. 1316 authorizes the CNW to operate over tracks of the MILW in Appleton, Wisconsin, for the purpose of providing continued railroad service to shippers served by those tracks.

DATES: Effective 11:59 p.m., July 15, 1979, and continuing until further order of this Commission.

FOR FURTHER INFORMATION CONTACT: J. Kenneth Carter, (202) 275-7840.

Decided July 13, 1979.

Upon further consideration of Service Order No. 1316 (43 FR 14668, 28497, 39796, 51024; and 44 FR 3715), and good cause appearing therefor:

It is ordered: § *1033.1316 Service Order No. 1316* (Chicago and North Western Transportation Company authorized to operate over tracks of Chicago, Milwaukee, St. Paul and Pacific Railroad Company at Appleton, Wisconsin) is amended by substituting the following paragraph (e) for paragraph (e) thereof:

(e) *Expiration date.* The provisions of this order shall remain in effect until modified or vacated by order of this Commission.

Effective date. This amendment shall become effective at 11:59 p.m., July 15, 1979.

(49 U.S.C. (10304-10305 and 11121-11126))

This amendment shall be served upon the Association of American Railroads. Car Service Division, as agent of all railroads subscribing to the car service and car hire agreement under the terms of that agreement and upon the American Short Line Railroad Association. Notice of this amendment shall be given to the general public by depositing a copy in the Office of the Secretary of the Commission at Washington, D.C., and by filing a copy with the Director, Office of the Federal Register.

By the Commission, Railroad Service Board, members Joel E. Burns, Robert S. Turkington and John R. Michael. Member John R. Michael not participating.

Agatha L. Mergenovich,

Secretary.

[FR Doc. 79-22647 Filed 7-20-79; 8:45 am]

BILLING CODE 7035-01-M

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Parts 25, 27, 28, 29, 32, and 33

The National Wildlife Refuge System; Administrative Corrections

AGENCY: Fish and Wildlife Service. Department of the Interior.

ACTION: Administrative Changes.

SUMMARY: This document provides for previous name changes and other administrative changes concerning certain units of the National Wildlife Refuge System, and updates cross-references in the text. These changes have resulted from previously issued Executive orders, public land orders and other administrative documents. This document makes no substantive changes and is being issued as a matter of reader convenience.

EFFECTIVE DATE: July 23, 1979.

FOR FURTHER INFORMATION CONTACT: Ronald L. Fowler, Division of Refuge Management, U.S. Fish and Wildlife Service, Washington, D.C. 20240, (202-343-4305) or Robert R. Poinsett, Division of Realty, U.S. Fish and Wildlife Service, Washington, D.C. 20240, (202-343-4026).

SUPPLEMENTARY INFORMATION: Due to the issuance of various administrative documents, the following changes have been identified as necessary to update the textual content of 50 CFR, Subchapter C. Cross-reference changes are also included. Other changes have been made to correct omissions, typographical errors, to indicate address changes for regional offices, and to reflect the transfer of function for power and energy to the Department of Energy (42 U.S.C. 7152). The appeals procedure for rights-of-way is also clarified to conform to 43 CFR Part 4, Subpart G. Ronald L. Fowler is the primary author of this document.

The name of Sanibel National Wildlife Refuge, Florida, was changed to J. N. "Ding" Darling National Wildlife Refuge on August 22, 1967. The Mason Neck National Wildlife Refuge Migratory Waterfowl Closed Area, Virginia is listed incorrectly under Louisiana. Lake St. Clair National Wildlife Refuge was transferred to the State of Michigan on November 15, 1963. However, the 4,200 acre Lake St. Clair Migratory Waterfowl Closed Area, which was closed by Presidential Proclamation No. 2593 on September 21, 1943, remains in effect and should now be referred to in § 32.4 as "Lake St. Clair, St. Clair and Macomb Counties, Michigan." Public Land Order 2441 on July 19, 1961, changed the name of Red Rock Lakes Migratory Waterfowl Refuge, Montana, to Red Rock Lakes National Wildlife Refuge. Also, Public Land Order 5635, dated April 25, 1978 (43 FR 19046), changed the name of the Charles M. Russell National Wildlife Range, Montana, to the Charles M. Russell National Wildlife Refuge. The designation of certain lands and waters of the Martin National Wildlife Refuge, Maryland, as a closed area (25 FR 7741) is erroneously listed under Louisiana.

The name of Havasu Lake National Wildlife Refuge, Arizona, was changed to Havasu National Wildlife Refuge by Public Land Order 4703 on October 1, 1969. The name of the Ravalli National Wildlife Refuge, Montana, was changed to Lee Metcalf National Wildlife Refuge on October 26, 1978 (43 FR 50061). Sevilleta National Wildlife Refuge, New Mexico, was added to the List of open areas; migratory game birds, on August 28, 1975 (40 FR 39518). The name of the Lower Souris National Wildlife Refuge, North Dakota, was changed to J. Clark Salyer National Wildlife Refuge on September 1, 1967.

The portion of the Killcohook National Wildlife Refuge in Delaware, became the Killcohook Wildlife Management Area and its administration was transferred to the State of Delaware on April 10, 1974. The Kentucky Woodlands National Wildlife Refuge, Kentucky, was transferred to the Corps of Engineers for conveyance to the Tennessee Valley Authority by Public Land Order 4560, dated December 27, 1968. Public Land Order 5634, dated April 25, 1978 (43 FR 19046), changed the names of the Charles Sheldon Antelope Range and the Charles Sheldon Wildlife Refuge, Nevada, and combined them as the Sheldon National Wildlife Refuge. Public Land Order 4079, dated August 26, 1966, changed the name of Desert Game Range, Nevada, to Desert National Wildlife Range. The name of Killcohook National Wildlife Refuge, New Jersey, was changed to Supawana Meadows National Wildlife Refuge on April 10, 1974. Santee National Wildlife Refuge, South Carolina, was added to the List of open areas; big game, on August 15, 1975 (40 FR 34348).

Executive Order 5493, on March 21, 1975, gave primary control of the Cabeza Prieta Game Range, Arizona, to the Fish and Wildlife Service and changed the name to Cabeza Prieta National Wildlife Refuge. Public Land Order 5637, dated April 25, 1978 (43 FR 19045), changed the name of the Kofa Game Range, Arizona, to Kofa National Wildlife Refuge. The name of the Snake Creek National Wildlife Refuge, North Dakota, was changed to Audubon National Wildlife Refuge on September 4, 1967 (32 FR 20888).

The Pishkun National Wildlife Refuge, Montana, was returned to the Bureau of Reclamation by Public Land Order 4466 on June 25, 1968. The listing for Arrowhead National Wildlife Refuge, North Dakota, should be corrected to Arrowwood National Wildlife Refuge. Pub. L. 93-402 (88 Stat. 801) established a national wildlife refuge in Virginia to be known as the Great Dismal Swamp National Wildlife Refuge which was erroneously published as Dismal Swamp National Wildlife Refuge.

The Service has determined that this action is not a rule as defined by 43 CFR 14.2 (43 FR 58292), and therefore the rulemaking provisions of 43 CFR Part 14 and Executive Order 12044 do not apply. Nor does this action constitute a significant rule within the meaning of 43 CFR 14.3 (43 FR 58296).

Since this action is editorial, entirely administrative in nature, and is intended for reader convenience, the Service has also determined that, even if 43 CFR Part 14 were applicable, rulemaking procedure is unnecessary, impracticable, and not in the public interest. For these same reasons, the Service concludes that "good cause" exists within the meaning of Section 553 of the Administrative Procedure Act to make these administrative changes effective upon publication.

Notwithstanding the above, it is the policy of the Department of the Interior, whenever possible, to afford the public the opportunity to comment on Departmental actions. Accordingly, interested persons may submit written comments, suggestions, or objections, on the revisions to the Director of the U.S.

Fish and Wildlife Service at the address given above at any time.

Therefore, 50 CFR Subchapter C—The National Wildlife Refuge System is corrected as follows:

PART 25—ADMINISTRATIVE PROVISIONS

§ 25.51 [Amended]

1. In § 25.51 General provisions, change 43 CFR Part 18 to 36 CFR Part 1227.

PART 27—PROHIBITED ACTS

§ 27.64 [Amended]

2. In §27.64 Prospecting and mining, change the second sentence to read as follows: See § 29.31 for provisions concerning mineral leasing.

PART 28—ENFORCEMENT, PENALTY, AND PROCEDURAL REQUIREMENTS FOR VIOLATIONS OF PARTS 25, 27, AND 28

§ 28.21 [Amended]

3. §28.21 General provisions, in the first sentence change 4 AM 4.9 to 4 AM 4.2.

PART 29—LAND USE MANAGEMENT

§ 29.21 [Amended]

4. In § 29.21 Definitions, paragraph (i) is revised as follows:

* * * * *

(i) "Department" means U.S. Department of the Interior unless otherwise specified, except for Department as used in section 29.21–8 which means the U.S. Department of Energy.

§ 29.21-1 [Amended]

5. In § 29.21–1 Purpose and scope, in subsection (c) change 42 CFR Part 2800 to 43 CFR Part 2800.

§ 29.21-2 [Amended]

6. In § 29.21–2 Application procedures, change subsection (a)(4) by replacing 36 FR 800 with 36 CFR Part 800.

* * * * *

Change § 29.21–2(c) to read as follows:

Regional or Area Director's Addresses. (1) For the States of California, Hawaii, Idaho, Nevada, Oregon and Washington:

Regional Director, U.S. Fish and Wildlife Service, Lloyd 500 Building, Suite 1692, 500 N.E. Multnomah Street, Portland, Oregon 97232.

(2) For the States of Arizona, New Mexico, Oklahoma, and Texas:

Regional Director, U.S. Fish and Wildlife Service, 500 Gold Avenue, P.O. Box 1306, Albuquerque, New Mexico 87103.

(3) For the States of Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin:

Regional Director, U.S. Fish and Wildlife Service, Federal Building, Fort Snelling, Twin Cities, Minnesota 55111.

(4) For the States of Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Puerto Rico, and Virgin Islands:

Regional Director, U.S. Fish and Wildlife Service, P.O. Box 95067, 17 Executive Park Drive NE., Atlanta, Georgia 30347.

(5) For the States of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, New Jersey, Pennsylvania, Rhode Island, Vermont, Virginia, and West Virginia:

Regional Director, U.S. Fish and Wildlife Service, One Gateway Center, Suite 700, Newton Corner, Massachusetts 03158.

(6) For the States of Colorado, Iowa, Kansas, Missouri, Montana, Nebraska, North Dakota, South Dakota, Utah, Wyoming:

Regional Director, U.S. Fish and Wildlife Service, P.O. Box 25486, Denver Federal Center, Denver, Colorado 80225.

(7) For State of Alaska:

Area Director, U.S. Fish and Wildlife Service, 1101 E. Tudor Road, Anchorage, Alaska 99503.

§ 29.21-8 [Amended]

7. In § 29.21–8 Electric power transmission line rights-of-way, change the reference in paragraph (c) from the Secretary of the Interior to the Secretary of Energy. Change the reference in paragraph (e)(2) from Department of the Interior to Department of Energy.

§ 29.22 [Amended]

8. In § 29.22 Hearing and appeals procedures, this section is revised as follows: An appeal may be taken from any final disposition of the Regional Director to the Director, U.S. Fish and Wildlife Service, and, except in the case of a denial of a right-of-way application, from the latter's decision to the Secretary of the Interior. Appeals to the Secretary shall be taken pursuant to 43 CFR Part 4, Subpart G.

§ 29.31 [Amended]

9. In § 29.31 Mineral ownerships in the United States, change the reference to provisions of "43 CFR 3103.2 and 3120.3–3" to "43 CFR 3101.3–3, 3109.4, 3201.1–6 and 3501.2–2".

PART 32—HUNTING

§ 32.4 [Amended]

10. In § 32.4 Areas closed to hunting.

* * * * *

Under Florida change Sanibel National Wildlife Refuge, Florida to J.N. "Ding" Darling National Wildlife Refuge.

* * * * *

Under Louisiana, correct the listing for Martin National Wildlife Refuge, as follows:

Aug. 13, 1960. Maryland * * * Martin National Wildlife Refuge * * * 25 FR 7741.

* * * * *

Under Michigan, substitute Lake St. Clair, St. Clair and Macomb Counties, Michigan, for Lake St. Clair National Wildlife Refuge.

* * * * *

Under Montana change Red Rock Lakes Migratory Waterfowl Refuge to Red Rock Lakes National Wildlife Refuge.

Also change Charles M. Russell National Wildlife Range, Montana, to Charles M. Russell National Wildlife Refuge.

* * * * *

§ 32.11 [Amended]

11. In § 32.11 List of open areas; migratory game birds.

Arizona

* * * * *

Change Havasu Lake National Wildlife Refuge to Havasu National Wildlife Refuge.

* * * * *

California

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Change Havasu Lake National Wildlife Refuge to Havasu National Wildlife Refuge.

* * * * *

Montana

* * * * *

Change Charles M. Russell National Wildlife Range to Charles M. Russell National Wildlife Refuge.

* * * * *

Change Ravalli National Wildlife Refuge to Lee Metcalf National Wildlife Refuge.

* * * * *

New Mexico

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Add Sevilleta National Wildlife Refuge.

* * * * *

North Dakota

* * * * *

Change Lower Souris National Wildlife Refuge to J. Clark Salyer National Wildlife Refuge.

* * * * *

§ 32.21 [Amended]

12. § 32.21 List of open areas; upland game.

Arizona

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Change Havasu Lake National Wildlife Refuge to Havasu National Wildlife Refuge.

* * * * *

Change Kofa Game Range to Kofa National Wildlife Refuge.

* * * * *

California

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Change Havasu Lake National Wildlife Refuge to Havasu National Wildlife Refuge.

* * * * *

Delaware

* * * * *

Delete Killcohook National Wildlife Refuge.

* * * * *

Kentucky

Delete Kentucky Woodlands National Wildlife Refuge.

* * * * *

Montana

* * * * *

Change Charles M. Russell National Wildlife Range to Charles M. Russell National Wildlife Refuge.

* * * * *

Change Ravalli National Wildlife Refuge to Lee Metcalf National Wildlife Refuge.

* * * * *

Nevada

Change Charles Sheldon Antelope Range to Sheldon National Wildlife Refuge.
Change Desert Game Range to Desert National Wildlife Range.

* * * * *

New Jersey

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Change Killcohook National Wildlife Refuge to Supawna Meadows National Wildlife Refuge.

* * * * *

North Dakota

* * * * *

Change Lower Souris National Wildlife Refuge to J. Clark Salyer National Wildlife Refuge.

* * * * *

§ 32.31 [Amended]

13. In § 32.31 List of open areas; big game.

Arizona

Change Cabeza Prieta Game Range to Cabeza Prieta National Wildlife Refuge.

* * * * *

Change Havasu Lake National Wildlife Refuge to Havasu National Wildlife Refuge.

* * * * *

Change Kofa Game Range to Kofa National Wildlife Refuge.

* * * * *

Kentucky

Delete Kentucky Woodlands National Wildlife Refuge and the heading "Kentucky."

* * * * *

Montana

Change Charles M. Russell National Wildlife Range to Charles M. Russell National Wildlife Refuge.

* * * * *

Change Ravalli National Wildlife Refuge to Lee Metcalf National Wildlife Refuge.

* * * * *

Nevada

Change Charles Sheldon Antelope Range to Sheldon National Wildlife Refuge.
Change Desert Game Range to Desert National Wildlife Range.

* * * * *

North Dakota

* * * * *

Change Lower Souris National Wildlife Refuge to J. Clark Salyer National Wildlife Refuge.

* * * * *

Change Snake Creek National Wildlife Refuge to Audubon National Wildlife Refuge.

* * * * *

South Carolina

* * * * *

Add Santee National Wildlife Refuge.

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PART 33—SPORT FISHING

§ 33.4 [Amended]

14. § 33.4 List of open areas; sport fishing.

Arizona

* * * * *

Change Havasu Lake National Wildlife Refuge to Havasu National Wildlife Refuge.

* * * * *

California

* * * * *

Change Havasu Lake National Wildlife Refuge to Havasu National Wildlife Refuge.

* * * * *

Kentucky

Delete Kentucky Woodlands National Wildlife Refuge and the heading "Kentucky."

* * * * *

Montana

* * * * *

Change Charles M. Russell National Wildlife Range to Charles M. Russell National Wildlife Refuge.

* * * * *

Delete Pishkun National Wildlife Refuge.
Change Ravalli National Wildlife Refuge to Lee Metcalf National Wildlife Refuge.

* * * * *

Nevada

Change Charles Sheldon Antelope Range to Sheldon National Wildlife Refuge.
Change Desert Game Refuge to Desert National Wildlife Range.

* * * * *

Delete Sheldon National Antelope Refuge.

* * * * *

North Dakota

Change Arrowhead National Wildlife Refuge to Arrowwood National Wildlife Refuge.

* * * * *

Change Lower Souris National Wildlife Refuge to J. Clark Salyer National Wildlife Refuge.
Change Snake Creek National Wildlife Refuge to Audubon National Wildlife Refuge.

* * * * *

Virginia

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Change Dismal Swamp National Wildlife Refuge to Great Dismal Swamp National Wildlife Refuge.

Dated: July 17, 1979.

Robert S. Cook,

Acting Director, U.S. Fish and Wildlife Service.

[FR Doc. 79-23260 Filed 7-20-79; 8:45 am]

BILLING CODE 4310-55-M

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 651

Atlantic Groundfish (Cod, Haddock, and Yellowtail Flounder)

AGENCY: National Oceanic and Atmospheric Administration (NOAA), Department of Commerce.

ACTION: Approval and partial disapproval of amendments to the Fishery Management Plan for Atlantic Groundfish; promulgation of emergency regulations and request for comments; notice of adjustments to catch limitations and of fishery closures.

SUMMARY: The Assistant Administrator for Fisheries has approved, with two exceptions, amendments to the Fishery Management Plan for Atlantic Groundfish (FMP) prepared by the New England Fishery Management Council. The approved amendments: (1) establish increases in the annual optimum yields and domestic commercial quotas for cod and haddock in both management areas; (2) revise the commercial quarterly allocations for cod and haddock in both management areas, consistent with the increases in the annual quotas; (3) restrict vessels fishing for cod or haddock in both the Gulf of Maine and Georges Bank and south areas to the higher of the appropriate weekly catch limitations from either area; and (4) revise the estimates of U.S. harvesting

capacity for cod and haddock. The regulations are amended by emergency action to reflect these amendments to the FMP.

New weekly catch limitations are established for all vessels fishing for cod and haddock in the Georges Bank and South area, for 0–60 GRT vessels and vessels fishing fixed gear for haddock in the Gulf of Maine, and for all vessels fishing for yellowtail flounder in the area east of 69° West longitude. The fisheries for cod in the Gulf of Maine by 0–60 GRT vessels and vessels fishing fixed gear are closed.

EFFECTIVE DATES: The emergency amendments to the regulations, the notice of adjustments of catch limitations, and the notice of fishery closures take effect July 22, 1979. The amendment to the regulation which ends "piggybacking" is also published as proposed rulemaking. Public comment on the proposed regulation is invited until September 18, 1979. The emergency regulations increasing cod and haddock OY's are effective until September 4, 1979, unless repromulgated before that date.

ADDRESSES: Written comments should be sent to the Regional Director, National Marine Fisheries Service, 14 Elm Street, Gloucester, MA 01930. Mark "Comments on groundfish regulations" on outside of envelope.

FOR FURTHER INFORMATION CONTACT: Dr. Robert W. Hanks, Deputy Regional Director, Northeast Region, National Marine Fisheries Service. Telephone (617) 281–3600.

SUPPLEMENTAL INFORMATION: On October 4, 1978, NOAA published emergency regulations (43 FR 45872) to implement the FMP on a fishing year basis (October 1–September 30), in response to amendments to the FMP prepared by the New England Fishery Management Council (Council). These emergency regulations were made final as of January 1, 1979 (44 FR 885).

FMP Amendments

The Council has submitted to the Secretary of Commerce amendments to its FMP which would increase the 1978–1979 fishing year optimum yields (OY's) for cod, haddock, and yellowtail flounder. The increase in OY's would be allocated to domestic commercial vessel classes for the fourth quarter of the fishing year (July 1–September 30, 1979). Amounts of fish presently allocated to the fourth quarter would be added to the third quarter (April 1–June 30, 1979) allocations.

The Council took this action after considering the social and economic impacts its FMP has had on the fishing industry since October 1, 1978, and after examining the initial analyses of the autumn 1978 bottom trawl assessment data from the National Marine Fisheries Service's Northeast Fisheries Center at Woods Hole, MA. These data show some improvement in the cod and haddock stocks. The numerous closures of species/area/vessel class fisheries for the regulated species since the start of the fishing year (43 FR 55411, 58570; 44 FR 6732, 22744, 24079) have caused disruptions in the fisheries with possible adverse social and economic impact on the fishery participants. Most vessel classes are rapidly approaching or have already exceeded their annual quotas established on October 1, 1978. Without increases in the quotas, other fishery closures during the fourth quarter would be necessary. The Council believes that maintaining harvest levels at the original quotas is inconsistent with its objectives for groundfish management, given the present condition of the fishery resource.

The Assistant Administrator, acting on behalf of the Secretary of Commerce, has approved the increases in the optimum yields and domestic commercial quotas for cod and haddock. The new OY for cod in the Gulf of Maine of 11,380 metric tons (mt) is below the reported commercial landings for calendar year 1978 of 12,242 mt. It is, however, in excess of the maximum sustainable yield (MSY) of 10,000 mt, which was specified in the original FMP of March 14, 1977 (42 FR 14064). The Council deliberately proposed this temporary OY above MSY because it believes the higher harvest level will not harm the stock on a short-term basis, and because it believes that the FMP's economic and social objectives will be served by the increase. The new OY for cod in Georges Bank and South of 34,960 mt is approximately equal to the reported 1978 landings of 35,419 mt (26,300 mt U.S. commercial and 9,119 mt Canadian). The new OY for haddock of 28,154 mt is moderately higher than the reported 1978 commercial catch of 26,957 mt (16,300 mt U.S. commercial and 10,657 mt Canadian). The increase is based on optimism over the prospects of a large 1978 year-class of haddock.

At the request of the Council, the Secretary is promulgating emergency regulations under section 305(e) of the Fishery Conservation and Management Act of 1976, as amended (the Act), to implement the increased OY's and domestic commercial quotas for cod and haddock. The purpose of the increase in the OY's is to prevent or postpone closures of cod and haddock fisheries during the period July through September. Such closures would disrupt fishing during the productive summer months with resulting severe economic and social effects on the fishermen and related industries. Further delay would not be in the best interest of the fishing industry.

The Council's proposed increases in the optimum yields for the yellowtail flounder fishery in both management areas (east and west of 69° West longitude) were disapproved by the Assistant Administrator and, therefore, will not be implemented. The yellowtail flounder resource continues to be at a low level of abundance compared with historic levels. While the autumn 1978 assessments indicate some improvement, the Council in its FMP amendment did not show adequately that the increased risk of population decline associated with increased levels of catch was appropriate from an examination of social and economic factors in the fishery. Further, the relationship of the proposed OY increases for yellowtail flounder to the Council's objectives for groundfish management was unclear. The proposed increases in OY's would have no impact on the Council's desire to manage the fishery without closures. The fishery west of 69° West longitude has exceeded even the proposed increased OY and would have to remain closed whether or not the OY were increased. The fishery east of 69° West longitude is unlikely to exceed the OY of 4,400 mt and would remain open without an increase in OY. Based on these factors, the Assistant Administrator determined that the Council has not provided a summary of the information utilized in making the specification of optimum yield required under section 303(a)(3) of the Act and disapproved the amendments.

In the fall of 1978, the New England Council voted to clarify the FMP to allow vessels fishing in more than one area (Gulf of Maine; Georges Bank and South) the opportunity to take their weekly catch limitations of cod and haddock from each area. This practice, commonly known as "piggybacking," has resulted in inaccurate reporting of area catches. As a consequence, the usefulness of commercial catch data has deteriorated for stock assessment purposes. Also, "piggybacking" has allowed vessels to catch their allocations more rapidly, so that early closures of fisheries were necessitated. For these reasons, the Council amended its FMP to restrict vessels fishing for cod or haddock to the appropriate weekly catch limitation from only one management area (i.e., Gulf of Maine or Georges Gank and South). A similar restriction has been in effect for vessels fishing for yellowtail flounder since October 1, 1978.

Elimination of a vessel's ability to "piggyback" catch limitations from both managment areas will assist in (1) spreading landings through quarters and the fishing year, and (2) enforcing the vessel catch limitation system. The Assistant Administrator has approved this FMP amendment and is implementing it through promulgation of emergency regulations, as the Council requested. Immediate implementation is necessary to prevent further circumventing of catch limitations and misreporting of catch locations that reduce the usefulness of landings data for resource assessment and management purposes.

The Council has also submitted to the Secretary an amendment to the FMP to revise upward its estimates of U.S. harvesting capacity for cod and haddock. The revisions are consistent with the original method of estimating U.S. harvesting capacity, which related capacity to past harvest levels and current allowable catches. The Assistant Administrator has approved this amendment; the estimates appear below in the revised Table 54.

Errata

A question has arisen concerning the Assistant Administrator's authority to adjust the catch limitations set forth in Appendix B to Part 651 within the limits prescribed in the FMP. The regulation implementing the FMP empowers the Assistant Administrator to adjust the catch limitations and overrun allowances downward only, to insure that closures are prevented. The Council believes § 651.23(f) of the regulations is not consistent with its intent to provide the Assistant Administrator with latitude to "adjust" these limitations within the maximum and minimum limits prescribed in the FMP. The Council intended the Assistant Administrator to have authority to adjust the limitations in Appendix B up or down, consistent with the vessel classes' quarterly allocations, in order to achieve an optimum yield from the fishery. Accordingly, § 651.23(f) is corrected to reflect this intent. Paragraph 651.23(b) of the regulations contains a reference to "applicable trip limitation." This is inconsistent with the remainder of § 651.23 and Appendix B of the regulations. These refer throughout to catch limitation(s). To avoid any possible confusion this error in 651.23(b) is corrected to read "applicable catch limitation."

Fishery Closures

The Regional Director, Northeast Region, National Marine Fisheries Service (Regional Director), has monitored the harvest of Atlantic groundfish for the period October 1, 1978 to June 15, 1979. Based on the landings statistics and the amounts of groundfish available for harvest through the end of the fishing year (September 30, 1979), the Regional Director has, pursuant to § 651.23(a), projected that the following vessel classes will have caught their annual allocations (less an anticipated amount to be caught incidentally during the period of closure) on July 22:

Cod, Gulf of Maine

0–60 GRT—Fixed gear.

Therefore the Regional Director has recommended to the Assistant Administrator that these fisheries be closed on July 22, 1979, for the remainder of the fishing year. The Assistant Administrator has reviewed the recommendations of the Regional Director and finds that closure of the cod fishery in the Gulf of Maine for the 0–60 GRT and fixed gear vessel classes on July 22 is necessary to prevent their annual allocations from being exceeded.

These two fishery closures are in addition to those implemented earlier in the fishing year. Therefore, all fisheries for cod in the Gulf of Maine are now closed. The 61–125 GRT and over 125 GRT vessel classes for haddock in the Gulf of Maine are also closed. The fishery for yellowtail flounder west of 69° West longitude is closed to all vessels. A revised Appendix B to this Part 651 reflects these closures and their dates of implementation. All vessels affected by a closure are limited to the incidental catch restrictions specified in § 651.24(d), as follows:

(1) Cod and haddock:

0–60 GRT—500 pounds or 4 percent by weight of all fish on board, whichever is the lesser amount, per trip.
61–125 GRT—1,000 pounds or 4 percent by weight of all fish on board, whichever is the lesser amount, per trip.
Over 125 GRT—2,000 pounds or 4 percent by weight of all fish on board, whichever is the lesser amount, per trip.
Fixed gear—500 pounds or 4 percent by weight of all fish on board, whichever is the lesser amount, per trip.

(2) Yellowtail flounder:

All vessels—500 pounds or 4 percent by weight of all fish on board, whichever is the lesser amount, per trip.

Adjustments to Catch Limitations

For the remainder of the species/area/vessel class fisheries, the Assistant Administrator has determined that catch limitations presently in effect will not allow vessel classes to harvest their allocations, as revised and specified in Appendix A to this Part 651. Pursuant to § 651.23(f), the Assistant Administrator has made the following adjustments in catch limitations, which appear in the revised Appendix B at the end of the regulations:

Cod, Georges Bank and South

0–60 GRT—increase from 4,900 to 7,000 pounds per week.
61–125 GRT—increase from 9,800 to 14,000 pounds per week
Over 125 GRT—increase from 14,000 to 20,000 pounds per week
Fixed gear—increase from 13,000 to 16,000 pounds per week

Haddock, Gulf of Maine

0–60 GRT—increase from 2,500 to 5,000 pounds per week
Fixed gear—increase from 8,000 to 16,000 pounds per week

Haddock, Georges Bank and South

0–60 GRT—increase from 3,500 to 7,000 pounds per week
61–125 GRT—increase from 7,000 to 14,000 pounds per week
Over 125 GRT—increase from 10,000 to 20,000 pounds per week
Fixed gear—increase from 8,000 to 16,000 pounds per week

Yellowtail Flounder, east of 69° W.
All vessels—increase from 5,000 to 6,000 pounds per week or trip, whichever time period is longer.

The revised catch limitations for cod and haddock for the Georges Bank and South area are the maximum allowed under the New England Fishery Management Council's FMP, as amended (43 FR 31015). All vessels fishing for yellowtail flounder are allowed the maximum catch limitation for the smallest vessel class (43 FR 31018). The Assistant Administrator anticipates that fishing at these catch levels will not result in the need during the remainder of this fishing year (September 30, 1979) for fishery closures. However, catches of all regulated species will continue to be monitored closely by the National Marine Fisheries Service. The FMP is amended as follows:

1. Table 54 is amended by striking the columns headed "Fishing Areas", "Optimum Yield", and "U.S. Capacity" and substituting the following:

Species	Fishing area	Optimum yield (in metric tons)	U.S. capacity (in metric tons)
Haddock	All areas (ICNAF 5)	28,254	40,000
Cod	Gulf of Maine (ICNAF 5Y)	11,380	16,000
	Georges Bank & South (ICNAF 5Z & SA 6)	34,960	40,000
Yellowtail flounder	East of 69° W. (ICNAF 5Ze)	4,400	20,000
	West of 69° (ICNAF 5Z & SA 6)	3,700	20,000

2. Section II.C.3(a) is amended by striking the last paragraph and substituting the following:

"The annual optimum yields for cod are specified as follows: Gulf of Maine—11,380 metric tons; Georges Bank and South—34,960 metric tons."

3. Section II.C.3.(c) is amended by striking the last paragraph and substituting the following:

"The annual optimum yield for haddock is 28,254 metric tons for the Gulf of Maine and Georges Bank and South."

4. Section II.C.4.A.(1)(a) is amended by striking "6,000" and substituting "8,880."

5. Section II.C.4.A.(1)(b) is amended by striking "22,000" and substituting "30,960."

6. Section II.C.4.A.(1)(c) is amended by striking the quarterly quotas for cod and substituting the following:

Quarter	Gulf of Maine [1]	Georges Bank and south [1]
Oct. 1–Dec. 31	1,420	5,640
Jan. 1–Mar. 31	1,400	4,600
April 1–June 30	3,180	11,760
July 1–Sept. 30	2,880	8,960
Totals	8,880	30,960

[1] In metric tons.

7. Section II.C.4.A.(3)(a) is amended by striking "18,000" and substituting "23,154."

8. Section II.C.4.A.(3)(b) is amended by striking the paragraph and substituting the following:

It is recommended that the haddock quota for the United States commercial fishery be allocated on a quarterly basis during the fishing year as follows:

Quarter	Gulf of Maine [1]	Georges Bank and south [1]
Oct. 1–Dec. 31	728	1,902
Jan. 1–Mar. 31	767	2,167
April 1–June 30	1,635	7,701
July 1–Sept. 30	1,998	6,256
Totals	5,128	18,026

[1] In metric tons.

9. A new Section II.C.4.E.(5) is added, as follows:

"Vessels which fish for groundfish in more than on management area are entitled to a catch limitation for only one area. The applicable limitation shall be the higher of the established catch limitations for the areas in which the vessel has fished."

The Supplemental Environmental Impact Statement on the OY increases and the "no piggybacking" amendment was filed with the Environmental Protection Agency in draft on April 13, 1979, and in final on June 27, 1979.

The Assistant Administrator finds that an emergency exists under provisions of Executive Order 12044, regarding the amendments to increase the OY's and to eliminate "piggybacking." The OY increases, as specified by the Council, will expire September 30. The "piggybacking" amendment, however, is published as a proposed rulemaking. Public comment on the amendment and regulation is invited for a period of 60 days, or until September 18, 1979.

(16 U.S.C. 1801 *et seq.*)

Signed at Washington, D.C., this 17th day of July, 1979.

Winfred H. Meibohm,

Executive Director, National Marine Fisheries Service

Part 651 is revised to read as set forth below:

(1) Section 651.23 is amended by:

(a) Renumbering paragraph 651.23(a) as 651.23(a)(1) and by adding a new 651.23(a)(2) and (3) as set forth below.

(b) Amending paragraph 651.23(b) by striking the word "trip" and substituting the word "catch".

(c) Amending paragraph 651.23(f)(1) by inserting after the word "exceed" the words "or fall short of".

§ 651.23 Catch limitations.

(a) * * *

(2) A vessel which fishes for cod and haddock in both management areas (Gulf of Maine, Georges Bank and South) during a week may land only the larger of the catch limitations from either area. A vessel may not land catch limitations from both areas".

(3) A vessel which fishes for yellowtail flounder in both management areas (east of 69° W. long., west of 69° W. long.) during a week or trip may land only the larger of the catch limitations from either area. A vessel may not land catch limitations from both areas.

* * * * *

(2) Appendices A and B to Part 651 are revised to read as follows.

Appendix A.—*Quarterly Quotas*

[Revised Effective July 22, 1979]

	Oct.-Dec. 78	Jan.-Mar. 79	Apr.-June 79	July-Sept. 79	Annual
Cod—Gulf of Maine (Commercial):					
Mobile gear					
0–60 GRT	581	699	1277	970	3527
61–125 GRT	342	277	528	530	1686
Over 125 GRT	180	171	110	112	573
Fixed gear	317	253	1265	1259	3094
Total	1420	1400	3180	2880	8880
Cod—Georges Bank and South (Commercial):					
Mobile gear					
0–60 GRT	501	593	1012	582	2688
61–125 GRT	1777	1567	3593	2168	9105
Over 125 GRT	2958	2129	4791	3764	13642
Fixed gear	404	311	2364	2446	5525
Total	5640	4600	11760	8960	30960
Haddock—Gulf of Maine (Commercial):					
Mobile gear					
0–60 GRT	183	146	660	621	1610
61–125 GRT	261	209	343	495	1308
Over 125 GRT	178	202	169	267	816
Fixed gear	106	210	463	615	1394
Total	728	767	1635	1998	5128
Haddock—Georges Bank and South (Commercial):					
Mobile gear					
0–60 GRT	86	40	307	306	739
61–125 GRT	650	662	2805	1977	6094
Over 125 GRT	1133	1393	4169	3322	10017
Fixed gear	33	72	420	651	1176
Total	1902	2167	7701	6256	18026

Appendix A.—*Quarterly Quotas*

[Revised Effective July 22, 1979]—*Continued*

	Oct.-Dec. 78	Jan.-Mar. 79	Apr.-June 79	July-Sept. 79	Annual
Yellowtail Flounder:					
East of 69° West (Commercial and Recreational)					
All classes	810	1500	640	1450	4400
Yellowtail Flounder					
West of 69 West (Commercial and Recreational)					
All classes	960	1150	890	700	3700

Appendix B.—*Catch Limitations*

[Revised Effective July 22, 1979]

Vessel class	Cod (pounds/week)* Gulf of Maine	Georges Bank & South
0-60 GRT	Closed July 22	7,000
61-125 GRT	Closed April 22	14,000
Over 125 GRT	Closed January 1	20,000
Fixed gear	Closed July 22	16,000

Vessel class	Haddock (pounds/week)* Gulf of Maine	Georges Bank & South
0-60 GRT	5,000	7,000
61-125 GRT	Closed April 22	14,000
Over 125 GRT	Closed January 1	20,000
Fixed gear	16,000	10,000

Vessel class	Yellowtail Flounder (pounds/week or trip)* West of 69° W.	East of 69° W.
0-60 GRT	Closed April 28	6,000
61-125 GRT	Closed April 28	6,000
Over 125 GRT	Closed April 28	6,000

* No overruns are allowed.

[FR Doc. 79-22565 Filed 7-20-79; 8:45 am]

BILLING CODE 3510-22-M

50 CFR Part 661

Salmon Fishery; Commercial and Recreational Salmon Fisheries off the Coasts of Washington, Oregon and California

AGENCY: National Oceanic and Atmospheric Administration/ Commerce.

ACTION: Final Regulations.

SUMMARY: This document makes final the regulations implementing the 1979 amendments to the fishery management plan for the commercial and recreational salmon fisheries off the coasts of Washington, Oregon, and California. As a result of a hearing before the District Court of Oregon, on July 11, 1979, in Confederated Tribes v. Kreps (C79-541), these regulations are under reconsideration but it was determined to publish them now with notice of the possibility of emergency changes under § 611.12. These regulations were originally published on April 25, 1979, as both proposed rulemaking and emergency regulations. Four petitions were subsequently received requesting a hearing on the emergency and proposed regulations. Recognizing the widespread interest in the regulations governing the Pacific Ocean salmon fisheries for 1979, the Assistant Administrator for Fisheries determined to conduct a non-oral proceeding. Notice was published in the Federal Register on June 4, 1979 establishing the non-oral proceeding and convening a select panel of fishery scientists to review all scientific evidence and comments.

After considering the recommendations of the select panel and public comments, the Administrator approved these regulations on July 27, 1979.

EFFECTIVE DATE: 0001 hours PDT July 18, 1979.

FOR FURTHER INFORMATION CONTACT: Mr. Donald R. Johnson, Northwest Regional Director, 1700 Westlake Avenue North, Seattle, Washington 98109, Telephone (206) 442-7575.

SUPPLEMENTARY INFORMATION: Fishery management plan (FMP's) for Commercial and Recreational Salmon Fisheries off the Coasts of Washington, Oregon, and California were adopted for the 1977, and 1978 seasons. The 1979 amendments to the FMP and the corresponding Supplemental Environmental Impact Statement were initially proposed by the Pacific Fishery Management Council (Council) in December 1978. Hearings were held during the public review period (December 8, 1978–February 28, 1979). Data and analyses became available during the public review period which indicated that many of the salmon stocks were likely to be in very low abundance in 1979, which required extending the public comment period and holding additional hearings. The public was invited to comment on the new evidence. The final amendments to the FMP, submitted by the Council in March 1979, are substantially more restrictive of ocean fishing than both the Council's initial proposal and the regulations in effect in 1978.

The four petitions received subsequent to the publication of the proposed and emergency regulations on April 25, 1979 were from: (1) The Washington State Commercial Passenger Fishing Vessel Association; (2) the All Coast Fishermen's Marketing Association; (3) certain Pacific Northwest Indian tribes; and (4) the Columbia River Indian tribes. The Federation of Independent Seafood Harvesters, Inc. submitted a later petition. The petitions requested that special consideration be given as to whether:

(1) Management measures for commercial ocean troll and recreational salmon fishing off the coast of Washington, more restrictive than those provided in the emergency and interim regulations, should be imposed to increase the number of salmon bound for the Columbia River, Washington coastal streams and Puget Sound tributaries for spawning and for allocation to the Indian fishermen, certain tribes being parties to the Columbia River Plan of February 28, 1977.

(2) Scientific evidence would justify more lenient treatment of the Makah Tribe, exempting tribal members from the barbless hook requirement and the 28" chinook minimum total length requirement for 1979.

(3) New evidence might require modifying conclusions regarding status of stocks for 1979.

(4) Scientific evidence indicates that additional emergency regulations further restricting the ocean salmon troll fishery were required in order to prevent overfishing of salmon stocks.

Comments

Eleven comments were received on the emergency ocean salmon regulations prior to announcement of the non-oral hearing (44 FR 32012, June 4, 1979). Most of the respondents requested relief from the 1979 emergency regulations imposed on the commercial troll fishery because they said the resource was in better condition than the Council and the Salmon Plan Development Team had predicted. Other respondents recommended more restrictive ocean fishing regulations in order to protect Treaty Indian fishing rights and to insure an adequate spawning escapement for critically depressed stocks.

One hundred and twenty-two comments were submitted following the Federal Register Notice June 4, 1979 announcing the special non-oral proceeding and the convening of the expert panel. Approximately 50% of those respondents represented commercial fishing interests. One-third of the respondents were divided among recreational anglers, Treaty Indian representatives, seafood processors/ distributors, charterboat owners and operators and "others." The remaining 17% were not identified with a particular interest group.

Respondents from the commercial fishing groups opposed the imposition of more restrictive ocean fishing regulations for the purpose of providing for additional salmon escapements to inshore areas. However, many commented that if it became apparent that more restrictive ocean fishing regulations were necessary in order to insure adequate spawning escapements, they could accept the more restrictive regulations only if such regulations were imposed uniformly on all ocean user groups. Commercial fishing respondents said that evidence did not exist which would justify new restrictive regulations in the commercial troll fishery. Most of the commercial fishing respondents believed that Council conclusions regarding the status of stock for 1979 were incorrect.

Such respondents opposed exemption of the Makah Tribe from regulations requiring the use of barbless hooks and minimum-size restrictions for chinook salmon as not being based on sound conservation principles.

Persons representing Treaty Indian fishing interests recommended that more restrictive ocean fishing regulations (commercial troll and recreational) be implemented immediately. They argued that the FCMA requires recognition of Treaty Indian rights and requires regulations reasonably calculated to fulfill those rights. They said the recent regulations fail to accomplish this mandate and the 1979 regulations were designed to maintain the status quo from 1978, which failed to fulfill Treaty Indian rights and provide for proper escapement in the Columbia River. Certain such respondents expressed belief that the 28" minimum size limit for chinook salmon and the barbless hook requirement were not necessary for conservation and therefore should not apply to the Makah Tribe. The Treaty Tribal respondents also disapproved of § 661.9(e) of the regulations as applied to treaty fishermen in the ocean which states that no persons engaged in commercial fishing shall take or retain steelhead on the grounds this requirement is not necessary for conservation.

Charterboat owners and operators and their representatives favored more restrictive regulations for the commercial troll fishery. However, they were not in favor of any further restrictions on the ocean recreational fishery. The representative for most of the Washington State charterboat owners and operators said that the regulations failed to provide them their fair share of fish. A further comment was that the present system is not reasonably calculated to promote conservation and protect all critically depressed coho stocks.

Recreational anglers, most of whom fish inshore waters, generally supported more stringent commercial ocean fishing regulations on the basis that the status of stocks indicated that more protection was needed for 1979.

Respondents from the seafood processing sector tended to voice the same opinions as the commercial harvesting sector. That is, they opposed more restrictive ocean regulations, discounted pre-season forecasts of stock abundances and rejected regulation modifications for the Makah Tribe.

Finally, all groups cited the destruction of habitat (due to logging practices and dam construction) as a major contributor to the declines in salmon abundance.

Response to Comments

In examining the responses of the petitioners and other commenters as well as the recommendations of the select panel in its report the Assistant Administrator for Fisheries concluded that there was no scientific basis for modifying earlier conclusions regarding status of stocks for 1979 and that management measures more restrictive than those provided in the emergency and proposed regulations on either the commercial ocean troll fishermen or the recreational fishermen should not be imposed. It was noted however, that the stocks, particularly coho stocks of the North Washington Coast would be closely monitored to determine whether in-seasons action under section 611.12 would be required. This conclusion was made prior to the Supreme Court decision in Washington v. Washington State Commercial Passenger Fishing Vessel Association and prior to the July 11, 1979 hearing in Confederated Tribes v. Kreps (C79-541). These conclusions and the regulations are being reviewed in light of those legal proceedings. The analysis set out below predates and does not address these legal matters.

The Pacific Fishery Management Council's Plan Development Team in its most recent status of salmon stocks report (June 13, 1979) noted that preliminary data from the 1979 season, although it is necessarily limited, does not indicate the need for any change in the 1979 regulations. Current indices indicate a greater numerical escapement of Columbia River chinook from the ocean in 1979 than was originally anticipated. Although the run size cannot yet be quantified, the expert panel, in its report, noted that the proportion of the chinook run escaping to the Columbia River from the ocean is likely to be greater than in 1978. Very little new data are available on coho since the commercial coho season does not begin until July. The team noted that the coho situation does not look promising and this also was concluded by the expert panel. A low level of catch per unit of effort of coho in the Washington ocean sport fishery during the first part of June could be an indication of a lower than expected return of coho salmon.

There remains concern for uniformity of regulations in different areas to avoid shifts along the coast that could have detrimental effects on many stocks. An increased closure of any length off Washington, which would increase the number of adult salmon escaping to the Columbia River, Washington coast, and Puget Sound tributaries, would result in shifts of fishing effort to areas off Oregon unless the waters in the fishery conservation zone (FCZ) off Oregon were closed. Similarly if the area off Oregon also were closed without a further closure in the FCZ off California, the result would be an effort shift and possible overfishing in waters off California depending on the magnitude of the shift. The management agencies (States and Federal government) have not been able to develop an area licensing or quota system to moderate effort shifts in their management of the ocean salmon fisheries in 1979.

On the other hand, a closure of the entire area off all three States in order to prevent overfishing caused by effort shifts could lead to overescapement which often results in reduced production of young fish and in wasted fish in some areas particularly off Oregon (south of Cape Falcon) and California where there are no inside terminal fisheries, with the exception of the Klamath River. In addition, changes that might increase escapement to the river systems and provide more fish for spawning and for inside fishermen, including Treaty Indians could be achieved only at a substantial loss to the ocean fishery directed at other stocks along the entire Pacific Coast. Current regulations are considered more restrictive than required for the escapement needs of California stocks, slightly more restrictive than required for Oregon stocks, and somewhat less restrictive than required for certain Washington stocks.

With respect to providing salmon to the Treaty Indian tribes, the United States is party to various treaties which secure a portion of the salmon stocks to the Treaty tribes on the Columbia River and elsewhere in the State of Washington. The United States is also party to the Columbia River Agreement which established in river sharing formulas and goals for the levels of salmon entering the river and bound for the upper Columbia. Good faith effort has been made to increase the proportion of the harvestable fish available to the up-river fishery in compliance with the Columbia River Agreement. In particular, the regulations governing the ocean fishery are intended to: (1) take steps to reduce waste in the ocean harvest and promote efficient utilization of stocks, (2) help achieve the goals of the Agreement through further escapement from the ocean fishery, and (3) make minimal the impact on spring and summer chinook. As noted by the select panel, the proportion of fish escaping from the ocean has steadily increased since the implementation of the first FMP in 1977, and the more stringent regulations this year should continue this trend.

It should be noted, however, that ultimate control over the fate of the salmon resource, including control over allocations in tribal fisheries, is only partly within the authority of the Secretary. The success of Secretarial decisions regarding the management of the ocean fishery is heavily dependent on actions taken by inside management authorities and, to an even greater extent, on actions taken by those entities with the ability to rehabilitate and/or preserve habitat.

In addition to the treaty obligations, the Council and the Secretary have other statutory obligations under the FCMA. The proposed regulations are designed to comply simultaneously with both "provisions of the Act" and "other applicable law." While the numerical goals set forth in the Agreement may not be achieved this year, the achievement of those goals depends on a number of factors, only one of which is ocean harvest. The FMP specifically recognizes those goals. For example, the optimum yield (OY) specified in the FMP is intended to achieve an average 17% increase in the proportion of upriver fall chinook escaping to inshore waters. This is predicted, over time, to contribute toward meeting the goal for this stock of an average in-river run of 300,000 adult fish.

With regard to the 1979 season, further closure of the salmon fishery north of Cape Falcon would be likely to (1) cause serious dislocation of the ocean fisheries with consequent detrimental impacts on slamon stocks in southern areas which remain open. Unequal closures along the coasts could compound management difficulties since measures to enforce such regulations have not been developed for the fishery. The select panel Report supports this finding and notes that, over time, any additional measures taken in the ocean should be made cautiously and incrementally so that the effects of such actions can be better perceived.

However, the District Court for Oregon has instructed the agency to evaluate whether these final regulations comply with the United States legal obligations to the Indian tribes, and to consider whether additional regulatory measures may be necessary to meet the legal duty. Notwithstanding the concerns expressed with regard to additional closures, such adjustments may be necessary and will be addressed by July 23, 1979. If closures are imposed, the agency will notify the fishing industry through the news and other appropriate broadcast media.

The Makah Tribe, as well as certain other tribes along the Washington Coast, have Treaty fishing rights in the FCZ. In recognition of these rights, the regulations have, since 1977, granted those tribes additional fishing time over that afforded the non-tribe commercial fishery.

Again in 1979, the regulations prohibited the non-tribal harvest of coho prior to July 1. In order to provide tribal fishermen additional harvest opportunity, the regulations exempted Makah fishermen from this restriction as well as the June 1–30, 1979, commercial closure.

In addition, the Makah Tribe wished to be exempted from the (1) requirement that all commercial fishermen in the FCZ, north of Cape Falcon, use barbless hooks prior to July 1, 1979, and (2) the minimum size limit of 28" for chinook salmon.

There is some argument for exemption from the barbless hook requirement since a major purpose of this gear is to reduce the mortality of coho salmon during the chinook-only season and the Makah, and other coastal tribes, are allowed to retain coho over 16" throughout the season. However, the use of barbless hooks will significantly decrease mortality of sublegal size coho and chinook shakers returned to the ocean. Therefore, their use has merit, especially during the early season, for conservation reasons.

The Makah Tribe maintains that the 28" size limit should not be applied to the tribal fishery since it is not for conservation purposes. This position is based, in part, on the fact that the recreational fishery is permitted to retain 24" chinook. The 28" size limit for chinook is biologically based and is intended to increase the total weight of production and to reduce the catch of immature 3-year-old fish and is intended to increase ocean escapement both for conservation and for inland treaty and non-treaty fisheries. The 24" size limit applying to ocean recreational fishing cannot be compared with the size limit applied to the commercial catch because the objective of recreational fishing is to participate in the catching of fish rather than the harvesting of a large total weight of fish. The lower size limit makes it possible for recreational fishermen to catch larger numbers of fish than would be the case with the larger size limit. However, recreational fishermen, by comparison, are limited to retention of two chinook or coho per day off the Washington Coast. The plan objective of maximizing the weight of the commercial catch is furthered by the 28" size limit, since salmon grow rapidly in the ocean. The Makah fishery is in large part a commercial fishery and the commercial size rather than the recreational size limit is appropriate.

The Assistant Administrator for Fisheries finds that because the 1979 season is already underway and fishermen are already familiar with these regulations, there is a good cause to make these regulations effective immediately. Final regulations are being published in order to provide a continuity of an orderly fishery following the time when the emergency regulations terminate on July 18, 1979. If changes are made in response to the legal proceedings, notice will be given as described above, as well as by Federal Register notice.

In accordance with Executive Order 12044, the Administrator of the National Oceanic and Atmospheric Administration has approved these regulations and a regulatory analysis. A copy of the analysis may be obtained by writing to Mr. Donald R. Johnson, address given above.

Signed at Washington, D.C., this the 17th day of July, 1979.

Winfred H. Meibohm,

Executive Director, National Marine Fisheries Service.

Part 661 is revised as follows:

PART 661—SALMON FISHERIES

Authority: 16 U.S.C. 1801 *et seq.*

§ 661.1 Purpose.

The purpose of this Part 661 is to provide for the management of the commercial and recreational salmon fisheries off the coasts of Washington, Oregon and California in the fishery conservation zone (also known as the 3-to-200 mile zone) over which the United States exercises exclusive fisheries management authority (i.e., the Pacific Fishery Management Council Salmon Management Area). This Part 661 implements the Pacific Council's fishery management plan for commercial and recreational salmon fisheries off the coasts of Washington, Oregon and California pursuant to authority conferred by the Fishery Conservation and Management Act of 1976, as amended.

§ 661.2 Relation to U.S.-Canada Sockeye and Pink Salmon Convention.

This Part 661 does not apply to fishing regulated under the Convention for the Protection, Preservation and Extension of the Sockeye Salmon Fishery of the Fraser River System, as amended by the Pink Salmon Protocol, north of 48° North latitude.

§ 661.3 Relation to State laws.

This Part 661 recognizes that any State law which pertains to vessels registered under the laws of that State, while in the Pacific Council Salmon Management Area, and which is consistent with the salmon management plan, including any State landing law, shall continue to have force and effect respecting fishing activities addressed herein.

§ 661.4 Definitions.

(a) Act—Means the Fishery Conservation and Management Act of 1976, as amended Pub. L. 94–265 (16 U.S.C. 1801–1882).

(b) Authorized Officer—Means:

(1) Any commissioned, warrant, or petty officer of the Coast Guard;

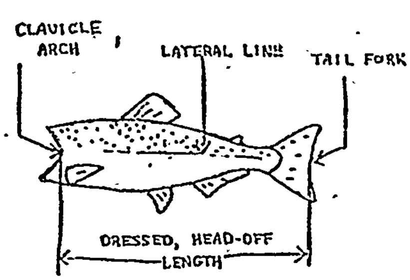
(2) Any certified enforcement agent or special agent of the National Marine Fisheries Service;

(3) Any officer designated by the head of any Federal or State agency which has entered into an agreement with the Secretary and the Secretary of Transportation to enforce the provisions of the Act; and

(4) Any Coast Guard personnel accompanying and acting under the direction of any person described in paragraph (1) of this subsection.

(c) Commercial Fishing—Means fishing for the purpose of sale or barter.

(d) Dressed, Head-off Length of Salmon—means the shortest distance between the mid-point of the clavicle arch and the fork of the tail, measured along the lateral line while the fish is lying on its side, without resort to any force or mutilation of the fish other than removal of the head, gills, and entrails.



(e) Dressed, Head-off Salmon—means salmon that have been beheaded, gilled and gutted, without further separation of vertebrae, and are either being prepared for on-board freezing, or are frozen and will remain frozen until landed.

(f) Fishing—Means:

(1) The catching, taking or harvesting of fish;

(2) The attempted catching, taking or harvesting of fish; or

(3) Any other activity which can reasonably be expected to result in the catching, taking or harvesting of fish.

(g) Fishing Vessel—means any boat, ship or other floating craft which is used for, equipped to be used for, or of a type which is normally used for fishing.

(h) Freezer Trolling Vessel—means a salmon trolling vessel which has capabilities for (1) on-board freezing of the catch, and (2) storage in a frozen state of the catch until it is landed.

(i) Land or Landing—Means bringing fish to shore or off-loading fish from a fishing vessel.

(j) Recreational Fishing—Means fishing for personal use of the catch. The catch, if any, is not used for sale or barter.

(k) Recreational Fishing Gear—Means conventional angling tackle consisting of a rod, reel and line, and hooks with bait or lures attached; recreational fishing gear must be held by hand by the angler while the angler is playing the fish and reducing it to possession.

(l) Salmon—Means any anadromous species of the family Salmonidae and genus *Oncorhynchus*, commonly known as Pacific salmon, including but not limited to:

Chinook (King) salmon—*Oncorhynchus tshawytscha.*
Coho (Silver) salmon—*Oncorhynchus kisutch.*
Pink (Humpback) salmon—*Oncorhynchus gorbuscha.*
Chum (Dog) salmon—*Oncorhynchus keta.*
Sockeye (Red) salmon—*Oncorhynchus nerka.*

(m) Total Length of Salmon—Means the shortest distance between the tip of the snout or jaw (whichever extends farthest while the mouth is closed) and the tip of the longest lobe of the tail, without resort to any force (other than fanning or swinging the tail) or mutilation of the salmon.

(n) Secretary—Means the Secretary of Commerce or a Designee.

(o) Single, Barbless Hook—Means a hook with a single shank and point, with no secondary point or barb curving or projected in any other direction. Hooks manufactured with barbs can be made "barbless" by forcing the point of the barb flat against the main part of the point.

(p) Troll Gear—Means commercial fishing gear which consists of one or more lines that drag hooks with bait or lures behind a moving fishing vessel, *and* which lines originate from a spool or receptacle which is fixed to the vessel during the fishing operation, *and* no part of this fishing gear is disengaged from the vessel at any time during the fishing operation.

§ 661.5 Salmon Fishery Management Areas.

(a) The Pacific Council Salmon Management Area shall be divided into the following management areas for the regulation of commercial and recreational salmon fishing, with the following boundaries:

(1) Management Area A—(i) Northern limit (the United States-Canada provisional International Boundary) is a line connecting the following coordinates:

48°29'37.19" N. lat., 124°43'33.19" W. long.;
48°30'11" N. lat., 124°47'13" W. long.;
48°30'22" N. lat., 124°50'21" W. long.;
48°30'14" N. lat., 124°52'52" W. long.;
48°29'57" N. lat., 124°59'14" W. long.;
48°29'44" N. lat., 125°00'06" W. long.;
48°28'09" N. lat., 125°05'47" W. long.;
48°27'10" N. lat., 125°08'25" W. long.;
48°26'47" N. lat., 125°09'12" W. long.;
48°20'16" N. lat., 125°22'48" W. long.;
48°18'22" N. lat., 125°29'58" W. long.;
48°11'05" N. lat., 125°53'48" W. long.;
47°49'15" N. lat., 126°40'57" W. long.;
47°36'47" N. lat., 127°11'58" W. long.;
47°22'00" N. lat., 127°41'23" W. long.;
46°42'05" N. lat., 128°51'56" W. long.;
46°31'47" N. lat., 129°07'39" W. long.

(ii) Southern limit: 45°46'00" N. lat. (Cape Falcon).

(2) Mangement Area B—(i) Northern limit 45°46'00" N. lat. (Cape Falcon).

(ii) Southern limit: 42°00'00" N. lat. (Oregon-California border).

(3) Management Area C—(i) Northern limits: 42°00'00" N. lat. (Oregon-California border).

(ii) Southern limit: (United States-Mexico International Boundary) is a line connecting the following coordinates:

32°35'22.11" N. lat., 117°27'49.42" W. long.;
32°37'37.00" N. lat., 117°49'31.00" W. long.;
31°07'58.00" N. lat., 118°36'18.00" W. long.;
30°32'31.20" N. lat., 121°51'58.37" W. long.

(b) Any person fishing subject to this Part 661 shall be bound by the above described international boundaries, notwithstanding any dispute or negotiation between the United States and any neighboring country regarding their respective jurisdictions, until such time as new boundaries are published by the United States.

(c) The inner boundary of each Management Area is a line coterminous with the seaward boundaries of the States of Washington, Oregon and California (the 3-"mile limit"), and the outer boundary of each Management Area is a line drawn in such a manner that each point on it is 200 nautical miles from the baseline from which the territorial sea is measured.

§ 661.6 General Restrictions.

The following restrictions apply to all commercial and recreational salmon fishing in Management Areas A, B, and C, except that the restrictions in this Part 661 shall not apply to fishing for pink and sockeye salmon regulated under the Convention for the Protection, Preservation, and Extension of the Sockeye Salmon Fishery of the Fraser River System, as amended by the Pink Salmon Protocol, North of 48° north latitude.

(a) No person shall use nets to fish for salmon except that a hand-held net may be used to bring hooked salmon on board a vessel.

(b) No person shall fish for, take or retain any species of salmon:

(1) During closed seasons or in closed areas specified in this Part;

(2) By means of gear or methods prohibited by this Part; or

(3) Once any catch limit specified in this Part is attained.

(c) No person shall take and retain any species of salmon which is less than the minimum length specified in this Part [see Subsections 661.4 (d), (e) and (h), 661.6 (f), (g), and (h), and 661.9 (c) regarding "Dressed, Head-off" salmon aboard a "Freezer Trolling Vessel"].

(d) No person shall fail to unhook and return to the water immediately and with the least possible injury any salmon the retention of which is prohibited by this Part.

(e) No person shall possess, have custody or control of, ship, transport, offer for sale, sell, purchase, import, export, or land any species of salmon or salmon part which was taken in violation of the Act, this Part, or any regulation issued under the Act.

(f) No person shall possess on board a fishing vessel any salmon taken in the Pacific Council's Salmon Management Area for which a minimum total length is set by these regulations, in such condition that its total length cannot be determined; except that "Dressed, Head-off" salmon, [as defined in § 661.4(e)] may be possessed aboard a "Freezer Trolling Vessel" [as defined in § 661.4(h)].

(g) No person, while fishing, shall possess on a fishing vessel during an open season in any Pacific Council Salmon Management Area, any salmon which is less than the minimum total length for that species in that Management Area; except that "Dressed, Head-off" salmon [as defined in § 661.4(e)] aboard a "Freezer Trolling Vessel" [as defined in § 661.4(h)] shall not be less than the "Dressed, Head-off Length" [as defined in § 661.4(d)] for that species in that Management Area.

(h) No person, while on board a fishing vessel, shall mutilate or otherwise disfigure any salmon in a manner which extends its length to conform to any minimum "Total Length" or "Dressed, Head-off Length" requirement specified in this Part. Salmon may be gilled and gutted, if in doing so there is no separation of vertebrae. In addition, on board a "Freezer Trolling Vessel" [as defined in § 661.4(h)] salmon may be prepared for on-board freezing [as defined in § 661.4(e)] if in doing so there is no further separation of vertebrae.

(i) No person shall:

(1) Refuse to permit an Authorized Officer to board a fishing vessel subject to such person's control for purposes of conducting any search or inspection in connection with the enforcement of this Act, this Part, or any other regulation issued under the Act;

(2) Forcibly assault, resist, oppose, impede, intimidate or interfere with any Authorized Officer in the conduct of any search or inspection described in paragraph (1) of this subsection;

(3) Resist a lawful arrest for any act prohibited by this Part; or

(4) Interfere with, delay, or prevent, by any means, the apprehension or arrest of another person by any Authorized Officer, knowing that such other person has committed any act prohibited by this Part.

§ 661.7 Facilitation of Enforcement.

The operator of each fishing vessel shall immediately comply with instructions issued by Authorized Officers to facilitate safe boarding and inspection of the vessel for purposes of enforcing the Act and this Part.

§ 661.8 Penalties.

Any person or fishing vessel found to be in violation of this Part 661 will be subject to the civil and criminal penalty provisions and forfeiture provisions prescribed in the Act.

§ 661.9 Commercial fishing.

(a) *Open seasons and areas.* The Pacific Council Salmon Management Area is closed to commercial salmon fishing except as opened by this Part or by superseding regulations. All open seasons shall begin at 0001 hours and terminate at 24000 hours local time on the dates specified herein.

(1) In Management Area A, the open season for salmon fishing shall be as follows:

(i) The season for all salmon species, except coho, shall begin on May 1, 1979 and terminate on May 31, 1979.

(ii) The season for all salmon species, including coho, shall begin on July 1, 1979 and terminate on September 8, 1979.

(2) In Management Area B, the open season for salmon fishing shall be as follows:

(i) The season for all salmon species, except coho, shall begin on May 1, 1979, and terminate on May 31, 1979.

(ii) The season for all salmon species, including coho, shall begin on July 1, 1979, and terminate on September 15, 1979.

(iii) The season for all salmon species except coho, shall re-open on September 16, 1979, and terminate on October 31, 1979.

(3) In Management Area C, the open season for salmon fishing shall be as follows:

(i) The season for all salmon species, except coho, shall begin on May 1, 1979, and terminate on May 23, 1979.

(ii) The season for all salmon species, including coho, shall begin on May 24, 1979, and terminate on June 15, 1979.

(iii) The season for all salmon species, including coho, shall re-open on July 1, 1979, and terminate on September 30, 1979.

(b) *Gear restrictions.* (1) No person shall engage in commercial salmon fishing using other than troll gear in the Pacific Council Salmon Management Area. However, in Management Area C, troll gear need not be fixed to the fishing vessel as specified in 661.4(p).

(2) No person shall engage in commerical salmon fishing in the Pacific Council Salmon Management Area using other than single, barbless hooks prior to July 1, 1979 in Management Areas A and B; or prior to May 24 in Area C; except that bait hooks with natural bait attached as the primary attraction and hooks on artificial salmon plugs may be barbed. Spoons, wobblers, dodgers, and flexible plastic lures shall not be considered artificial salmon plugs under this subparagraph, and therefore must be equipped with barbless hooks in all Management Areas, and during the time periods described in this sub-paragraph 661.99(b)(2).

(c) *Length Restrictions.* Minimum total length of salmon and minimum dressed, head-off length of salmon are as follows:

		Minimum—total length [1]	Minimum—Dressed, head-off length [1]
Area A	Chinook	28	21½
	Coho	16	12
Area B	Chinook	26	19½
	Coho	16	12
Area C	Chinook	26	19½
	Coho	22	16½
All Areas	Species other than Chinook and Coho.	None	None.

[1] In inches.

(d) *Vessel Inspection and Certification.* Any vessel 26 feet or longer with coho salmon on board in Management Area C between May 24 and June 2, 1979, shall have on board documentation of 1979 hold inspection required by the State of California.

(e) *Steelhead.* No person engaged in commercial fishing shall take and retain or possess any steelhead (*Salmo gairdneri*) within the Pacific Council Salmon Management Area.

§ 661.10 Recreational fishing.

(a) *Open seasons and areas.*—The Pacific Council Salmon Management Area is closed to recreational salmon fishing except as opened by this Part or by superseding regulations. All seasons shall begin at 0001 hours and terminate at 2400 hours local time on the dates specified herein.

(1) In Management Areas A and B, the season shall open on May 12, 1979, and terminate on September 16, 1979.

(2) In Management Area C, the season shall open on February 17, 1979, and teminate on October 14, 1979.

(a) *Gear restrictions.*—(1) No person shall engage in recreational salmon fishing in the Pacific Council Salmon Management Area using other than recreational fishing gear as defined in Part 661.4(k), to which may be attached not more than one artificial lure or natural bait, with no more than four single or multiple hooks.

(2) No person shall use more than one rod and line for recreational salmon fishing in Management Areas A and B; however, there shall be no limit to the number of rods and/or lines used for recreational salmon fishing in Management Area C.

(3) No person engaged in recreational fishing for salmon in Management Area C may use weights of more than four (4) pounds attached directly to the line.

(c) *Length restrictions.*—Minimum total lengths of salmon are as follows:

		Minimum—total length [1]
Area A	Chinook	24
	Coho	16
Area B	Chinook	22
	Coho	16
Area C	Chinook and Coho	22 [2]
All	Species other than Chinook and Coho	None

[1] In inches.
[2] Except that one chinook or coho salmon per day may be less than 22 inches but not less than 20 inches.

(d) *Catch limits.* No person shall take and retain, or possess more than two chinook or coho salmon in the aggregate per day while in the Pacific Council Salmon Management Area; except that in Area A the catch and possession limit shall be three salmon, no more than two of which shall be chinook or coho salmon.

§ 661.11 Treaty Indian Fishing.

(a) Persons entitled to exercise rights under the Treaty with the Makah may fish for all salmon species in that portion of Management Area A north of 48°07'36" North latitude (Sandy Point) from 0001 hours on May 1, 1979, to 2400 hours on October 31, 1979. Except as specified by this subsection (a), such persons are subject to the provisions of this Part 661, the Act, and any other regulation issued undert the Act.

(b) Members of the Quileute and Hoh Tribes entitled to exercise rights under the Treaty of Olympia, may fish for all salmon species in that portion of Management Area A south of 48°07'36" North latitude (Sandy Point) and north of 47°31'42" North latitude (mouth of Queets River) from 0001 hours on May 1, 1979, to 2400 hours on October 31, 1979. Except as specified by this subsection (b), such persons are subject to the provisions of this Part 661, the Act, and any other regulations issued under the Act.

(c) Members of the Quinault Tribe entitled to exercise rights under the Treaty of Olympia, may fish for all salmon species in that portion of Management Area A south of 47°40'5" North latitude (Destruction Island) and North of 46°53'3" North latitude (Point Chehalis) from 0001 hours on May 1, 1979, to 2400 hours on October 31, 1979. Except as specified by this subsection (c), such persons are subject to the provisions of this Part 661, the Act, and any other regulations issued under the Act.

(d) The Secretary will give due consideration in promulgating emergency regulations under § 661.12 to the treaty fishing rights of Indian tribes with usual and accustomed fishing grounds in the area affected by such regulations.

§ 661.12 Emergency Regulations.

(a) The Secretary may issue emergency regulations under Section 305(e) of the Act, if an emergency involving the salmon resource is determined to exist. Emergency regulations will be announced by publication of a notice in the Federal Register. Information on emergency regulations will be disseminated to affected persons through appropriate news media.

(b) The Council may, at any time, make recommendations to the Secretary for emergency regulations under this section.

§ 661.13 Catch Reports.

This Part recognizes that catch and effort data necessary for implementation of this Fishery Management Plan shall be collected by the States of Washington, Oregon and California under existing State data collection provisions. No additional catch reports will be required of fishermen or processors as long as the data collection and reporting systems operated by state agencies continue to provide the Secretary with statistical information adequate for management. Reporting requirements may be promulgated by emergency regulations if this reporting system becomes inadequate for management purposes.

§ 661.14 Test Fisheries.

The Secretary may, upon recommendation of the Pacific Council, allow in the Pacific Council Salmon Management Area such limited test fisheries for scientific purposes as may be proposed by the Pacific Council, the Federal Government, State Governments and Treaty Indian Tribes having usual and accustomed fishing grounds in the Pacific Council Salmon Management Area.

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Proposed Rules

Federal Register
Vol. 44, No. 142
Monday, July 23, 1979

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

COST ACCOUNTING STANDARDS BOARD

[4 CFR Parts 417, 418, and 419]

Cost Accounting Standards; Indirect Cost Allocation

AGENCY: Cost Accounting Standards Board.

ACTION: Proposed Rule.

SUMMARY: The Board on March 16, 1978 proposed five Standards which would deal with the allocation of various indirect costs. After analysis of the five proposed Standards in the light of comments submitted in response to them, the Board concluded that the issues being dealt with could be covered in three, rather than five, Standards. The Standards have been revised and the resultant three Standards are being published today for comment. When adopted the Standards will apply to negotiated national defense contracts subject to Pub. L. 91-379.

DATE: Comments are due September 20, 1979.

FOR FURTHER INFORMATION CONTACT: Arthur Schoenhaut, Executive Secretary, Cost Accounting Standards Board 441 G Street N.W., Washington, D.C. 20548, 202-275-6111.

SUPPLEMENTARY INFORMATION: On March 16, 1978, the Cost Accounting Standards Board published five proposed Cost Accounting Standards on cost allocation. The proposals were Part 417—Distinguishing Between Direct and Indirect Costs; Part 418—Allocation of Service Center Costs; Part 419—Allocation of Material—Related Overhead Costs; Part 420—Allocation of Manufacturing, Engineering and Comparable Overhead Costs; Part 421—Allocation of Indirect Costs. Comments were received from 86 sources on the proposals.

One frequent comment was that it was not necessary to have five separate Standards to deal with these cost allocations. Various suggestions were made as to ways in which the proposals could be combined. Upon further analysis of the proposals in the light of these comments and additional research data obtained from a number of contractors, it appears feasible to reduce the number of Standards to three. Proposed CAS 417 continues to be a separate proposal. For the reasons set forth below, the Board now proposes to combine the originally proposed Standards 418 and 421 into a single proposal designated as CAS 418—Allocation of Indirect Cost Pools. Similarly the originally proposed CAS 419 and 420 are now merged into a single proposal identified as CAS 419—Allocation of Overhead Costs of Productive Functions and Activities.

Another prevalent comment received in response to the proposals was that promulgation of the five Standards in their original form would lead to unnecessary proliferation of indirect cost pools. The Board has examined the reasons for this concern and concludes that readers anticipated that the proposals, if adopted, might be administered and construed to compel the establighed of separate pools in circumstances under which the Board would not consider such separation to be necessary. As detailed in the discussion of the individual Standards being proposed today, revisions have been made to avoid generation of unnecessary pools.

Cost Accounting Standard 417—Distinguishing Between Direct and Indirect Costs

As proposed today, Cost Accounting Standard 417 provides criteria designed to achieve consistency in determining which costs shall be specifically identified with and allocated to the final cost objectives of a period as direct costs. All costs that satisfy these criteria must be accounted for as direct costs. Generally, costs not meeting the criteria for a direct cost shall be classified as indirect costs. This proposal reflects the following conclusions by the Board with respect to comments on the original proposal.

1. *Definitions.*—A number of comments discussed the Board's definitions of "Direct Cost", "Indirect Cost," and "Indirect Cost Pool". Many commentators said that limiting these definitions solely to the relationship of incurred costs to "final" cost objectives could cause problems. These definitions were originally promulgated in 1972. The Board's research covering the ensuing 7 years has not produced any evidence of a significant problem in the costing and administration of contracts resulting from the use of these definitions. The Board therefore proposes to retain the original definitions without change.

Comments also questioned the meaning of the terms "resource" and "homogeneous indirect cost pools," as those terms were used in the fundamental requirement of the originally proposed CAS 417. In response, the Board has included a definition of "resource" in its revisions to proposed CAS 417 and 418, and has deleted references to "homogeneous indirect cost pools" in CAS 417. Issues relating to such indirect cost pools will be dealt with in Standards that are more specifically concerned with indirect cost allocations (cf. proposed revision of Cost Accounting Standard 418).

2. *Clear and exclusive test.*—Several commentators criticized the requirement that there must be a clear and exclusive benficial or causal relationship between the incurrence of a cost and a final cost objective to allow the cost to be accounted for as a direct cost. They believe this requirement is too rigid and could drastically restrict direct cost classification.

The concept of a clear and exclusive beneficial or causal relationship as a primary characteristic of a direct cost has long been recognized in Government contract cost accounting. The Board believes that inclusion of this criterion in the proposed Standard, therefore constitutes a minimal constraint. Although some changes in the wording of § 417.50(a) have been made to clarify the Board's intent, the basic requirement has been retained.

3. *Costs of a resource that vary with its consumption.*—The proposal published on March 16, 1978, provided that, "Costs identified with a resource used directly on or applied directly to a final cost objective shall be limited to the costs of that resource that vary directly with its consumption." This was widely misinterpreted as dealing with variable costs as contrasted with fixed costs. The primary purpose of this provision was to indicate that if a contractor desires to include costs such as fringe benefits and material related

expenses as part of direct labor and direct material costs, he could do so only if the costs varied directly with the consumption of the direct labor or direct material. In considering the comments received on this point, the Board concluded that a statement of this type was not necessary in this Standard and it has been deleted.

4. *Interchangeability.*—The March 16, 1978, proposal contained a provision, § 417.50(b), authorizing the averaging of unit costs in determining the amount of direct cost allocable to individual final cost objectives covering quantities of labor, material, etc., that are specifically identified with the final cost objectives. This provision required that the resources, the costs of which are to be averaged, be interchangeable. Several commentators questioned the interchangeability requirement, contending that this was too restrictive. The Board considers the situations covered by this provision to be comparable to those where the use of labor-rate Standards or material-price Standards are authorized under 4 CFR 407. The interchangeability requirement is intended to insure the homogeneity of the resources whose costs are being averaged, and is similar to the requirements spelled out in more detail in § 407.50 (a) and (b). The provisions of § 417.50(b) have therefore been retained with only minor wording changes to conform with the definition of the term, "resource."

5. *Cost accounting treatment for service centers, process cost centers, etc.*—The earlier proposal, in § 417.50(c), required that costs allocated to final cost objectives from a service center were to be treated as "other direct costs" to preclude treatment of those costs as direct labor or direct material cost. This treatment was proposed because allocations from service centers are generally made on a composite cost basis for services provided by the service center. Nonetheless many commentators objected to this limitation, and suggested that contractors should be able to allocate costs separately as direct labor, direct materials, other direct costs, and overhead if the contractor maintains the cost breakouts required for such separate identification.

The earlier proposal also contained a provision, § 417.50(d), that was intended to cover process cost centers and other situations in which there was common production of goods for a number of different final cost objectives. It authorized treatment of the costs incurred in such situations as direct costs provided that allocation was made on the basis of a cost per unit of output. Objections were also raised to limiting the coverage to the production of "goods" and limiting the basis for allocation to units of output.

In response to these comments on paragraphs § 417.50 (c) and (d), the Board has combined them into a new § 417.50(c). This paragraph covers the common production, in process cost centers, service centers, etc., of both goods and services. This new provision permits the separate identification of direct labor costs, direct material costs, other direct costs, and overhead costs. It also provides for allocation, as direct costs of final cost objectives, to be made on the basis of either resource consumption or output.

6. *"Blanket" (distributed) direct costs.*—A number of commentators recommended that the Standard provide for so-called "blanket" (distributed) direct labor and direct material costs. This refers to the practice, common in certain types of businesses, of accumulating and separately allocating the costs that are incurred directly in the production of goods or services required by multiple final cost objectives in increments too small and numerous to justify the record keeping that would be necessary to provide specific identification. The allocation in these circumstances is made separately for the labor or material costs, by means of various types of averaging techniques, standard costs, or algorithmic measures.

The Board has partially accepted this recommendation by proposing to provide, also in § 417.50(c), for allocations of "blanket" direct labor and direct material costs as direct costs. However such allocations must be made in conformance with 4 CFR 418.50(b) (1) and (2). The Board believes that cost distributions using allocation bases that do not conform to this requirement are too remote from specific identification to merit classification as direct costs.

Cost Accounting Standard 418—Allocation of Indirect Cost Pools

Cost Accounting Standard 418 being proposed today provides guidance for the accumulation of costs in indirect cost pools and the selection of allocation measures based on the beneficial or causal relationship between the costs and the benefiting cost objective. The proposal provides guidance for evaluating the homogeneity of an indirect cost pool and establishes a hierarchy of allocation measures. The hierarchy is (1) a measure of resource consumption, (2) an output measure, (3) a surrogate for consumption, or (4) a measure representative of the entire activity being managed.

The determination that the allocation of pooled costs to cost objectives is in reasonable proportion to the beneficial or causal relationship of the pooled costs to those cost objectives, is satisfied when the allocation base used is the best available representation of resource consumption. Therefore when steps (1) and (2) of the hierarchy of allocation measures are applied, the necessary degree of specific identification of the cost of resource consumption is obtained and such costs may be accounted for as direct costs in accordance with the provision of CAS 417.50(c). Allocation bases which are in accordance with steps (1) and (2) are measures of the activity being performed—either the consumption of resources or the output of the activity—as opposed to allocation bases provided by steps (3) and (4) which are measures derived from the activity of the cost objective causing the costs or receiving the benefit. Accordingly, bases derived under steps (3) and (4) do not provide the necessary degree of specific identification of the cost of resource consumption and such costs may be accounted for only as indirect costs.

The costs of resources used are initially allocated to an indirect cost pool or to a final cost objective. The indirect cost pools are intermediate cost objectives under the full costing concept of cost allocation as used by the Board. Indirect cost pools can be allocated periodically (e.g., at the end of an accounting period) or continuously as they occur (e.g., through the use of a computer program or a preestablished rate). Indirect cost pools are either productive (e.g., process cost center) pools, service (e.g., service center) pools, overhead pools or general and administrative (G&A) cost pools. Costs are allocated from these cost pools in accordance with the hierarchy of allocation base preferences to other indirect cost pools and to final cost objectives until all costs are accumulated in final cost objectives, thus determining the total cost of those final cost objectives. Costs accumulated in indirect cost pools can be allocated to other indirect cost pools, to overhead pools, to G&A pools and to final cost objectives.

Commentators observed that the principles and concepts in the originally proposed CAS 421 were the same as in the other four proposed indirect cost allocation Standards and suggested that there was no need for the proposed CAS 421 which set forth criteria and guidance for items of indirect cost not covered by a specific Standard. The Board believes that the need for these criteria and guidance continues by that it can be provided within the framework of CAS 418 being proposed today. Similarly, in line with the combining of the two Standards and the comments received there is no need to deal with the term service center since the concept of service center is within the scope of the term "indirect cost pool."

1. *Relationship to other standards.*—Several commentators indicated doubt as to the reltionship of coverages in the five allocation Standards published in March 1978. They were concerned about the possibility that some indirect cost might be covered by more than one allocation Standard despite the statement to the contrary in the purpose section of the previously proposed CAS 421. To deal with this concern, a provision has been included in the revised Fundamental Requirement, that indirect costs whose allocation is provided for in any other Cost accounting standard (e.g., 4 CFR 410 and proposed 4 CFR 419) shall not be allocated under this standard.

2. *Charges for services.*—Commentators voiced a number of concerns relating to the allocation of the cost of service centers to various cost objectives of a business unit. The commentators were concerned that the originally proposed Standard 418 would prevent their making "casual sales" of services to outsiders; that the sale of services would be required to be at cost rather than at a market determined price; and that management would be required to charge other parts of its business organization the full cost of the services rather than a management determined amount. All of the above concerns relate to managerial needs and decisions and are not infringed upon by the requirements of the standard. The originally proposed Standard would not have prevented management from making sales of services, nor would it have set the "price" at which services must be sold. Further, it would not have established the amounts which management charges its departments or other segments for budgetary or other management reasons. It would have established the cost accounting to determine the cost of services which are allocated to Government contracts. Accordingly, the Board has made no change in this aspect of the Standard being proposed today.

3. *Use of pre-established rates.*—The earlier proposal on Allocation of Service Center costs provided guidance for using Standard Cost in allocating the costs of a service center. A number of commentators acknowledged that the use of the term "Standard Cost" was appropriate for Cost Accounting standard 407, but said that for the purpose of allocating indirect cost pools including service centers the term "pre-established rates" was more appropriate and more widely understood. The Board agrees and has revised the proposal to incorporate the term "pre-established rates."

4. *Revision of indirect cost rates.*—Commentators expressed uncertainty over the requirements of the proposal concerning the revision of indirect cost rates. The Board believes that indirect cost rates should be reviewed as needed to properly reflect the anticipated costs and activities for the full cost accounting period. The revised proposal includes changes to clarify the requirement that indirect cost rates be annualized and to provide guidance for interim revisions of annual rates.

5. *Allocation of costs among service centers.*—Respondents characterized the previously published § 418.50(d) as being unduly rigid and restrictive regarding the allocation of costs among service centers. The Board has changed the requirements in the previously published § 418.50(d). As now proposed in § 418.50(e), any method of recognizing services rendered to other indirect cost pools is allowed as long as the allocation method achieved results not significantly different from those that would be provided by cross-allocation among indirect cost pools.

Cost Accounting Standard 419—Allocation of Overhead Costs of Productive Functions and Activities

Cost Accounting Standard 419 being proposed today is entitled "Allocation of Overhead Costs of productive Functions and Activities." It covers the overhead costs incurred in the production of all goods and services and provides criteria for establishing overhead cost pools. These costs are part of a business unit's indirect costs. The proposed Standard also provides criteria concerning the composition of pools and the composition and selection of allocation bases.

1. *Potential proliferation of overhead pools.*—Many commentators expressed concern that Standards 419 and 420 as previously proposed would result in an unnecessary proliferation of overhead pools. The Standard being proposed today has been phrased in terms which the Board believes more clearly describes the circumstances in which separate overhead pools are needed. As a consequence, the Standard being proposed should eliminate much of this concern.

a. *Material-related overhead costs.*—A number of commentators suggested that material-related overhead costs should be included in cost pools with other overhead costs and that allocation bases used for the other overhead pools can properly allocate such material-related overhead costs. Other commentators were of the opinion that material-related activities are in essence no different from other productive activities. Some said that material-related overhead costs are not significant for some contractors. For these reasons commentators said the originally proposed CAS 419 was unnecessary.

The Board agrees that the previously proposed CAS 419 is unnecessary as a separate Standard. Material-related overhead costs can be dealt with in the same Standard dealing with other overhead costs of productive functions and activities.

b. *Definition and use of the term "Productive Activity".*—The proposed definition of "Productive Activity" said in part, "A manufacturing *operation*, such as machining, assembling and *heat treating* in the manufacturing functions * * *" (Emphasis added.) A large number of commentators expressed concern that use of "operation" and "heat treating" in the context of the originally proposed CAS 420 might result in contractors being required to establish an inordinate number of overhead pools.

The word "operation" does not mean that each detailed process required in the production of goods or services constitutes a "productive activity." It refers only to a major process or a group of such processes. For this reason, reference to "heat treating" has been deleted.

(c) *Materiality test.*—The previously proposed CAS 420 would have required separate overhead pools whenever a business unit performed productive functions or activities disproportionately on cost objectives. Many commentators expressed concern that application of this requirement to productive activities would result in an unreasonable proliferation of overhead pools.

The Board's objective is to assure that the beneficial or causal relationships governing the contractors' overhead allocations are reflected in the cost accounting practices of contractors generally. A large number of contractors already maintain overhead pools for productive activities. Others will be required to establish overhead pools for productive activities to accomplish the objective of the Standard. To minimize the possibility of unreasonable proliferation of overhead pools, however, a special materiality test is included in the Standard being proposed today. The creation of additional overhead pools would not be necessary unless the additional pools would result in a materially different allocation of overhead costs to a significant contract subject to the proposed Standard. A material difference occurs when the allocation to any such contract by the addition of any pool differs by 5 percent or more from the amount that would otherwise be allocated to that contract. Establishment of additional overhead pools making no significant difference in cost allocation to contracts is not warranted even if the productive functions or activities are performed disproportionately on the contracts. The proposed Standard leaves to the parties to determine which contracts are significant. Other tests were considered for use in determining which contracts are significant, such as (1) the absolute dollar amount of a contract, or (2) the relationship of the contract amount to the business unit's total revenue.

The Board also considered overall measures of materiality that would result in (1) not requiring an additional pool unless its creation would result in a change in the amount allocated to any covered contract which would be greater than a specified percentage of the value of the overhead pool, and (2) not requiring an additional pool unless its creation would result in a change in the amount allocated to any covered contract which would exceed an absolute dollar amount.

Another approach considered by the Board was to base materiality on the impact of any change in allocation on an overall basis, such as (1) the change between the allocation to all of a contractor's covered contracts as a group and all of its other contracts, or (2) the change in allocation among different types of contracts subject to the Standard (i.e., firm-fixed price, fixed price incentive, cost-plus-fixed fee, etc.).

The Board is interested in your views on the desirability of using a particular objective or subjective materiality measure. The Board also invites comments on the merits of using the materiality test set forth in the proposed Standard compared with other possible materiality tests including those described above.

2. *Composition of a pool.*—The previously proposed CAS 420 provided that costs of special facilities such as wind tunnels, space chambers and reactors generally should be excluded from overhead pools. A number of commentators suggested that this was an improper treatment and that the cost of these facilities should be treated as normal overhead costs.

These facilities normally are used by a limited number of cost objectives. The Board believes that the facilities costs, therefore, should be allocated only to those cost objectives. Accordingly, the Standard being proposed today provides that such costs, if material, generally must be excluded from overhead cost pools, unless the base used for allocating the overhead cost pools reasonably represents the usage of such special facility by each cost objective. However, a materiality text similar to that governing the establishment of overhead pools is included in the Standard which would permit the costs of special facilities to be included in overhead cost pools if they meet the test.

3. *Allocation bases.*

a. *Uncompensated overtime hours.*—Under the previously proposed CAS 420, uncompensated overtime hours directly worked on cost objectives would be included in a direct labor hour base. A number of commentators said that controlling and recording such overtime hours would be difficult.

The cost that would result from requiring the uncompensated overtime hours to be controlled and recorded appears to outweigh the benefits to be derived. Accordingly, this requirement is being omitted from the Standard being proposed today.

b. *Purchased Labor.*—The previously proposed CAS 420 contained a requirement for the use of a direct labor hour base whenever a contractor used purchased labor under certain conditions. Commentators stated that this restriction was unnecessary and recommended that use of a direct labor cost base be permitted. Because this recommendation has merit whenever an equivalent labor cost can be established for purchased labor, use of a direct labor cost base is permitted under the proposal being published today.

c. *Customer furnished materials.*—The previously proposed CAS 419 provided for inclusion of the value of customer furnished materials in a direct material cost base. Most commentators deemed this requirement to be impractical. They noted that frequently an accurate value is impossible to obtain; reaching agreements as to the value would be time consuming and difficult; or the value cannot be obtained in a timely manner to be reflected in contractor's proposals. The Board is persuaded that the costs involved in determining and including the value of customer furnished materials in a direct material base would outweigh the benefits to be derived in most instances. Accordingly, this requirement has been changed to provide that if the parties can agree on the value of customer furnished materials, such value may be included in the allocation base.

d. *Stock or product inventory.*—A member of commentators suggested that whenever items are produced for stock or product inventory, and there is a separate material-related overhead pool, costs should be allocated only once to these items. The Board agrees and has revised the Standard accordingly.

1. Part 417 is proposed to read as follows.

PART 417—DISTINGUISHING BETWEEN DIRECT AND INDIRECT COSTS

Sec.

Authority: Sec. 719 of the Defense Production Act of 1950, as amended, Pub. L. 91-379, 50 U.S.C. App. 2168.

§ 417.10 General applicability.

General applicability of this Cost Accounting Standard is established by § 331.30 of the Board's regulations on applicability, exemption, and waiver of the requirement to include the Cost Accounting Standards contract clause in negotiated defense prime contracts and subcontracts (4 CFR 331.30).

§ 417.20 Purpose.

The purpose of this Cost Accounting Standard is to provide criteria for distinguishing direct costs from indirect costs based on the relationship of costs to final cost objectives.

§ 417.30 Definitions.

(a) The following are definitions of terms prominant in this Standard:

(1) *Allocate.* To assign an item of cost, or a group of items of cost, to one or more cost objectives. This term includes both direct assignment of cost and the reassignment of a share from an indirect cost pool.

(2) *Cost objective.* A function, organizational subdivision, contract or other work unit for which cost data are desired and for which provision is made to accumulate and measure the cost of processes, products, jobs, capitalized projects, etc.

(3) *Direct cost.* Any cost which is identified specifically with a particular final cost objective. Direct costs are not limited to items which are incorporated in the end product as material or labor. Costs identified specifically with a contract are direct costs of that contract. All costs identified specifically with other final cost objectives of the contractor are direct costs of those cost objectives.

(4) *Final cost objective.* A cost objective which has allocated to it both direct and indirect costs, and, in the contractor's accumulation system, is one of the final accumulation points.

(5) *Indirect cost.* Any cost not directly identified with a single final cost objective, but identified with two or more final cost objectives or with at least one intermediate cost objective.

(6) *Indirect cost pool.* A grouping of incurred cost identified with two or more cost objectives but not identified with any final cost objective.

(7) *Resource.* A unit of labor, materials, or other type of input to the productive or administrative activities of a business.

§ 417.40 Fundamental requirement.

(a) The cost of a resource shall be accounted for as a direct cost and shall be allocated only to a final cost objective if:

(1) The beneficial or causal relationship between the incurrence of the cost and that final cost objective is clear and exclusive; and,

(2) The amount of the cost is readily and economically measurable without undue administrative effort; and,

(3) All other costs incurred for the same purpose in like circumstances can be identified specifically with particular final cost objectives and accounted for as direct costs in compliance with 4 CFR Part 402.

(b) Costs which do not satisfy the criteria of (a) above shall be identified and account for as indirect costs of final cost objectives.

§ 417.50 Techniques for application.

(a) The relationship between the incurrence of the cost of a resource and a final cost objective is clear and exclusive if the resource is identifiable with that final cost objective, and can be measured and separated from resources used on other cost objectives without undue administrative effort.

(b) The amount of cost to be allocated as a direct cost to final cost objectives may be determined on the basis of an average cost of the resources used or applied whenever the resources are interchangeable.

(c) Notwithstanding the requirements of paragraph .40(a), whenever costs incurred in the common production of goods or services required by multiple cost objectives are allocated to final cost objectives in accordance with 4 CFR 418.50(b)(1) and (2), such costs may be accounted for as direct costs. When accounted for in this manner, they may be allocated to the final cost objectives by charges covering all cost elements for each unit of output, or separately as direct labor, direct materials, other direct costs, or overhead. In making the allocations covered under this provision, average or standard costing techniques may be used.

(d) Direct costs of minor dollar amount may be accounted for as indirect costs as provided for in 4 CFR 402.50(e).

§ 417.60 Illustrations.

(a) Contractor A has various classifications of engineers whose time is spent in working directly on the production of the goods or services called for by contracts and other final cost objectives. Detailed time records are kept of the hours worked by these engineers, showing the job/account numbers representing various cost objectives. On the basis of these detailed time records, Contractor A allocates the labor costs of these engineers as direct labor costs of final cost objectives. This practice is in accordance with the requirements of § 417.40(a).

(b) Contractor B has personnel who work on budgets, job cost analyses and reports, under circumstances in which their time cannot practically and economically be identified with particular final cost objectives on a consistent basis. Contractor B accounts for the labor costs of these employees as indirect costs. This is in accordance with the requirements of § 417.40(b).

(c) Contractor C has a paint shop, employees of which spray-paint units of the work-in-process of multiple final cost objectives. These employees are grouped by labor skills and pay rate, and records are maintained of the time spent by each employee on the work identified with particular final cost objectives. An average wage rate is established for each group. These average rates are applied consistently to the hours worked on each cost objective by employees in each group. The resultant costs are allocated as direct labor costs directly to each final cost objective as work is performed. This cost accounting treatment is in accordance with the provisions of § 417.50(b).

(d) Contractor D has a plating shop, but is not able to readily and economically identify the labor time spent on particular final cost objectives. Contractor D establishes the plating shop as a service center, the composite labor, material and other costs of which are allocated to final cost objectives based on a measurement of output, and these allocations are treated as other direct costs. This practice is in accordance with § 417.50(c). If Contractor D had maintained separate identification of cost elements in the allocation of costs from this service center, the costs could then have been accounted for as direct labor, direct materials, other direct costs, and overhead of the final cost objectives.

(e) Contractor E has a shop where metal parts are dipped into chemical liquids for cleaning purposes. Parts for many different final cost objectives are processed through the shop every day, and it is not practical to identify the time of the shop employees with specific final cost objectives. The Contractor accumulates the labor cost of the shop separately, and allocates it as direct labor to the final cost objectives using as a base the direct labor cost charged against those final cost objectives for the manufacturing processes preceding the chemical dipping operation. Because Contractor E did not meet the requirements set forth in § 417.50(c), the shop labor cost may not be accounted for as direct labor of the final cost objectives.

(f) Contractor F uses a process cost system in the production of parts and components which are to be used on multiple final cost objectives. The accumulated labor, material and other costs of each process are identified with the output of that process on the basis of a composite cost per unit of such output. The costs thus identified with particular units of output are subsequently allocated from the process cost center as direct material costs of the individual final cost objectives with which the output is specifically identified. This practice is in accordance with § 417.50(c).

(g) Contractor G uses a job order cost system. Low-unit cost, high-volume materials are used extensively during the manufacturing fabrication and assembly processes. These materials are issued to departmental organizations performing fabrication and assembly activities of the manufacturing function that specifically identify their labor hours and labor dollars with particular final cost objectives. The material usage on the cost objectives does not vary directly with the direct labor used on those cost objectives. The costs of the low-unit cost, high volume materials element of each organization's cost are identified with and allocated to the final cost objectives as direct material costs by assignment to each final cost objective in the same proportions as the direct labor hours of the shops that use the materials. Because Contractor G did not meet the requirements of § 417.50(c), the costs of the low-unit cost, high-volume materials must be accounted for as indirect costs.

(h) Contractor H has an engineering function in which 30 engineering supervisors are responsible for supervision of 150 engineers performing technical tasks on 10 contracts. The labor costs of the 150 engineers are specifically identified with and allocated directly to the particular contracts on which their work is being performed. The 30 supervisors responsible for these direct labor costs, and their clerical assistants, allocate their labor costs to a work order assigned specifically for the accumulation of such costs. These work order costs are prorated at the end of each month to the 10 contracts on the same basis as the distribution is made of the direct labor hours worked by the 150 engineers. This prorated supervisory and clerical effort is accounted for as direct labor cost of the 10 contracts. Contractor H's practice covering allocation of costs of the 30 supervisors and their clerical assistants does not meet the hierarchical allocation requirements of § 417.50(c); therefore, the costs of all of these engineering supervisors and their clerical assistants must be classified as indirect costs.

(i) Contractor I has as part of an assembly operation a department which uses a large number of low cost brackets which are attached to frames. The number of brackets attached to each frame is determined from engineering drawings. The number and cost of the brackets are identified and allocated to final cost objectives as direct material costs. Contractor I allocates the labor effort of attaching the brackets to final cost objectives using a rate per bracket—a measure of the output of this department. Since this allocation satisfies the requirements of § 418.50(b)(2), the labor costs of attaching the brackets can be accounted for as direct labor costs of final cost objectives in accordance with the provisions. of § 417.50(c).

§ 417.70 Exemptions.

None for this Standard.

§ 417.80 Effective date.

(a) The effective date of this Standard is [reserved].

(b) This Standard shall be followed by each contractor on or after the start of his next cost accounting period beginning after the receipt of a contract to which this Cost Accounting Standard is applicable.

2. Part 418 is proposed to read as follows.

PART 418—ALLOCATION OF INDIRECT COST POOLS

Sec.

Authority: Sec. 719 of the Defense Production Act of 1950, as amended, Pub. L. 91-379, 50 U.S.C. App. 2168.

§ 418.10 General applicability.

General applicability of this Cost Accounting Standard is established by § 331.30 of the Board's regulations on applicability, exemption, and waiver of the requirement to include the Cost Accounting Standards contract clause in negotiated defense prime contracts and subconstracts (4 CFR 331.30).

§ 418.20 Purpose.

The purposes of this Cost Accounting Standard are (1) to provide criteria for the accumulation of indirect costs in indirect cost pools, including service centers, and (2) to provide guidance relating to the selection of allocation measures based on the beneficial or causal relationship between an indirect cost pool and cost objectives. Consistent application of these criteria and guidance will improve indirect cost allocation.

§ 418.30 Definitions.

(a) The following are definitions of terms prominent in this Standard:

(1) *Allocate.* To assign an item of cost, or a group of items of cost, to one or more cost objectives. This term includes both direct assignment of cost and the reassignment of a share from an indirect cost pool.

(2) *Indirect cost.* Any cost not directly identified with a single final cost objective, but identified with two or more final cost objectives or with at least one intermediate cost objective.

(3) *Indirect cost pool.* A grouping of incurred costs identified with two or more cost objectives but not identified specifically with any final cost objective.

(4) *Overhead cost.* An indirect cost of a productive function or activity.

(5) *Resource.* A unit of labor, materials, or other type of input to the productive or administrative activities of a business.

§ 418.40 Fundamental requirement.

(a) Indirect costs shall be accumulated in indirect cost pools which are homogeneous.

(b) Pooled costs shall be allocated to cost objectives in reasonable proportion to the beneficial or causal relationship of the pooled costs to those cost objectives. Pooled costs shall be allocated by means of one of the following bases of allocation, listed in descending order of preferability: (1) a resource consumption measure, (2) an output measure, (3) a surrogate that is representative of resources consumed, or (4) a measure that is representative of the entire activity being managed.

(c) Indirect costs that are required to be allocated by application of any other Cost Accounting Standard may not be allocated under this Standard. Indirect costs which are overhead costs of productive functions or productive activities shall be allocated to final cost objectives according to the provisions of 4 CFR 419.

§ 418.50 Techniques for application.

(a) *Homogeneous indirect cost pools.* (1) An indirect cost pool is homogeneous if all the activities whose costs are included therein have the same or similar beneficial or causal relationship to cost objectives as the other activities whose costs are included in the cost pool or if the allocation of the costs of the activities included in the cost pool results in an allocation to cost objectives which is substantially the same as it would be if the costs of the activities were allocated separately.

(2) When an indirect cost pool includes the costs of one or more activities which do not have the same or similar beneficial or causal relationship to cost objectives as the other activities in the cost pool, the pool is not homogeneous. The costs of activities having a dissimilar relationship shall be removed from the cost pool and shall be allocated in accordance with the provisions of this or other appropriate Cost Accounting Standards if the resulting allocation of these costs would be substantially different when allocated separately.

(3) Where an activity included in an indirect cost pool consumes one or more types of resources which do not have

the same or similar beneficial or causal relationship to cost objectives as the other resources accounted for in the cost pool, the pool is not homogeneous. the cost of these resources shall be removed from the cost pool and allocated in accordance with the provisions of this or other appropriate Cost Accounting Standards if the resulting allocation would be substantially different when allocated separately.

(b) *Hierarchy of allocation measures.* The determination that the allocation of pooled costs to cost objectives is in reasonable proportion to the beneficial or causal relationship of the pooled costs to those cost objectives, shall be satisfied when the allocation base used is the best available representation of resource consumption.

(1) The preferred representation of the relationship between an indirect cost pool and the benefiting cost objective is a measure of resource consumption of the activity or activities represented by the indirect cost pool. This relationship can be measured in circumstances where there is a direct and definitive relationship between the activity or activities and the benefiting cost objectives. In such cases, a single unit of measure can generally represent the consumption of resources in performance of the activities represented by the indirect cost pool. Measures of resource consumption ordinarily can be expressed in such terms as labor hours, machine hours or other consumption measures. Accordingly, these indirect cost pools shall be allocated by use of a rate, such as a rate per labor hour or a rate per machine hour or other consumption rate of the activity.

(2)(i) If consumption measures are unavailable or impractical to ascertain, the preferred basis for allocation shall be a measure of the output of the activity or activities represented by the indirect cost pool. Thus, the output shall become a substitute measure for the consumption of resources. Output can be measured in terms of units of end product produced by the activities, as for example, number of printed pages for a print shop or number of purchase orders processed by a purchasing department.

(ii) In circumstances in which the level of resource consumption varies among the units produced by the activities represented by the indirect cost pool, the use of the basic unit of output as a measure will not reflect the proportional consumption of resources. Consequently, where a material difference will result the measure shall be modified or more than one measure shall be used to reflect the resources consumed to perform the activity.

(3) If neither resources consumed nor output of the activities can be measured practically, a surrogate shall be used to measure the resources consumed. Surrogates used to represent the relationship generally measure the activity of the cost objective receiving the service and shall vary in proportion to the services received. An example of a surrogate base is the number of personnel served by a personnel department. Number of personnel served may reasonably represent the use of resources of the personnel function for the cost objectives receiving the services, where this base varies in proportion to the services performed.

(4) Indirect cost pools which cannot readily be allocated on measures of a specific beneficial or causal relationship generally represent the cost of overall management activities. Such costs do not have a direct and definitive relationship to the benefiting cost objectives. These costs should be grouped in relation to the activities managed and the base selected to measure the allocation of these indirect costs to cost objectives should be a base representative of the entire activity managed. For example, the total cost of plant activities managed might be a reasonable base for allocation of general plant indirect costs. The use of a partial measure of activity, such as direct labor costs or direct material cost only, as a substitute for a total activity base is acceptable only if the base is representative of the total activity being managed.

(c) *Simultaneous services.* Where the activity or activities represented by an indirect cost pool provide services to two or more cost objectives simultaneously, the cost of such services shall be prorated between or among the cost objectives in reasonable proportion to the beneficial or causal relationship between the services and the cost objectives.

(d) *The use of pre-established rates for indirect costs.* (1) preestablished rates, based on either forecasted actual or standard costs, may be used in allocating an indirect cost pool. Where variances of a cost accounting period are material, these variances shall be disposed of by allocating them to cost objectives in proportion to the costs previously allocated to these cost objectives by use of the pre-established rates.

(2) Where pre-established rates are used to allocate the cost of an indirect cost pool, these rates shall reflect the costs and activities anticipated for the cost accounting period. Such pre-established rates shall be reviewed at least annually, and revised as necessary to reflect the anticipated conditions.

(3) Pre-established rates used for allocating indirect cost pools may be revised during a cost accounting period.

(i) The revised rates shall reflect the costs and activities anticipated for the entire cost accounting period.

(ii) If the accumulated variances are significant, the costs previously allocated shall be adjusted to the amounts which would have been allocated using the revised pre-established rates.

(e) *Recognition of services received from or provided to other indirect cost pools.* (1) Allocation of indirect cost pools to all benefiting cost objectives shall include recognition of the benefit to other indirect cost pools. The method used shall result in an allocation which is not significantly different from that which would be obtained through using cross-allocation to reflect the services provided to and received from other indirect cost pools.

(2) Allocation may be made exclusively to final cost objectives only if the results are not materially different from the results to be obtained if costs were allocated to all benefiting cost objectives.

§ 418.60 Illustrations.

(a) Contractor A accumulated the costs relating to building ownship cost, maintenance cost, and utility cost into one indirect cost pool designated "Occupancy Costs" for allocation to cost objectives. Each of these activites has the same or a similar beneficial or causal relationship to the cost objectives occupying space. Contractor A's practice is in conformance with the provisions of § 418.50(a)(1).

(b) Contractor B includes the costs of systems analysis and applications programming, central processing unit operations, and off-line printer operations in a single indirect cost pool entitled "Data Processing Center." The systems analysis and applications programming activity does not have the same or similar beneficial or causal relationship to cost objectives as the other activities in the pool designated "Date Processing Center." Also, the allocation of the cost of this activity to cost objectives would be significantly different if allocated separately from the other costs of the "Data Processing Center." The costs of the systems analysis and applications programming activity must be separately allocated to cost objectives in accordance with the provisions of § 418.50(a)(2).

(c) Contractor C accounts for the costs of its technical typing services as an indirect cost pool. In selecting an allocation measure for this indirect cost pool, Contractor C establishes that consumption measures are unavailable and impractical to ascertain, and decides on using the number of typed pages as the allocation measure. Contractor C's selection of an output measure for the allocation of the cost of the typing services is in conformance with provisions of § 418.50(b)(2).

(d) In accordance with § 418.50(a) Contractor D includes all the cost of occupancy in an indirect cost pool. In selecting an allocation measure for this indirect cost pool, the contractor establishes that it is impractical to ascertain a measurement of the consumption of resources in relation to the use of facilities by individual cost objectives. An output base, the number of square feet of space provided to users, can be measured practically; however, the cost to provide facilties is significantly different for various types of facilities such as warehouse space, factory space and office space and each type of facility requires a different level of resource consumption to provide the same number of square feet of usable space. Allocation on a basic unit measure of square feet of sapce occupied will not adequately reflect the proportional consumption of resources. Contractor D establishes a weighted square foot measure for allocating occupancy costs, which reflects the different levels of resource consumption required to provide the different types of facilities. This practice is in conformance with provisions of § 418.50(b)(2)(ii).

(e) Contractor E has an indirect cost pool containing a significant amount of material-related costs. The contractor allocates these costs between his machining overhead cost pool and his assembly overhead cost pool. The contractor finds it impractical to use an allocation measure based on either consumption or output. The contractor is required to use a surrogate base that varies in proportion to the services rendered. The contractor selects a material-issued base which varies in proportion to the services rendered. The contractor's practice is in conformance with the provisions of § 418.50(b).

(f) Contractor F accounts for the costs of company aircraft in a separate homogeneous indirect cost pool and allocates the cost to benefiting cost objectives using flight hours. Contractor F prorates the cost of a single flight between benefiting cost objectives whenever simultaneous services have been rendered. Manager of Contract 1 requests and uses a company plane for a 5 hour trip. Manager of Contract 2 learns of the trip and goes along with Manager of Contract 1. Contractor F prorates the cost of the trip between Contract 1 and Contract 2. This practice is in conformance with the provision of § 418.50(c).

(g) During a cost accounting period Contractor G allocates the cost of his flight services indirect cost pool to other indirect cost pools and final cost objectives using a pre-established rate. The pre-established rate is based on an estimate of the actural costs and activity for the cost accounting period. For the cost accounting period, Contractor G establishes a rate of $200 per hour for use of the flight services activity. In March the contractor's operating environment changes significantly; the contractor now expects a significant increase in the cost of this activity during the remainder of the year. The contractor estimates the rate for the entire cost accounting period to be $240 an hour. Pursuant to the provsions of § 418.50(d) the Contractor may revise his rate to the expected $240 an hour. Because the accumulated variances are deemed to be significant, the contractor must also adjust the costs previously allocated to reflect the revised rates.

(h) Contractor H has five indirect cost pools which provide services to indirect cost pools and to other cost objectives. Contractor H does not allocate the cost of these five indirect cost pools to the other indirect cost pools which receive their services; rather, he allocated all of their costs to the other cost objectives. Pursuant to the provision of § 418.50(e) Contractor H may continue to allocate the costs of these services using this practice if he can demonstrate that this practice does not result in a materially different allocation of costs to final cost objectives than would be obtained through cross allocation among the five indirect cost pools.

§ 418.70 Exemptions.

None for this Standard.

§ 418.80 Effective date.

(a) The effective date of this Standard is [reserved].

(b) This Standard shall be followed by each contractor on or after the start of his next cost accounting period beginning after the receipt of a contract to which this Cost Accounting Standard is applicable.

3. Part 419 is proposed to read as follows.

PART 419—ALLOCATION OF OVERHEAD COSTS OF PRODUCTIVE FUNCTIONS AND ACTIVITIES

Sec.

Authority: Sec. 719 of the Defense Production Act of 1950, as amended, Pub. L. 91-379, 50 U.S.C. App. 2168.

§ 419.10 General applicability.

General applicability of this Cost Accounting Standard is established by Section 331.30 of the Board's regulations on applicability, exemption, and waiver of the requirement to include the Cost Accounting Standards contract clause in negotiated defense prime contracts and subcontracts (4 CFR Part 331.30).

§ 419.20 Purpose.

The purpose of this Cost Accounting Standard is to provide criteria for accumulating overhead costs of productive functions and activities and for allocating such costs to cost objectives of a business unit based on the beneficial or causal relationship between the costs and the cost objectives. Consistent application of these criteria will improve cost allocation.

§ 419.30 Definitions.

(a) The following are definitions of terms prominent in this Standard.

(1) *Allocate.* To assign an item of cost, or a group of items of cost, to one or more cost objectives. This term includes both direct assignment of cost and the reassignment of a share from an indirect cost pool.

(2) *Business Unit.* Any segment of an organization or an entire business organization which is not divided into segments.

(3) *Final Cost Objective.* A cost objective which has allocated to it both direct and indirect costs, and, in the contractor's acumulation system, is one of the final accumulation points.

(4) *Overhead cost.* An indirect cost of a productive function or activity.

(5) *Productive Activity.* An operation, such as machining or assembling in the manufacturing function; designing, developing or testing in the engineering function; base maintenance and support, communication services, training, or field engineering and technical services in a service function; or others such as material related activities.

(6) *Productive Function.* A group of productive activities such as those related to manufacturing, engineering or services.

§ 419.40 **Fundamental requirement.**

(a) Those indirect costs of a business unit which are overhead cost shall be accumulated in one or more homogeneous cost pools.

(b) Such costs shall be allocated only to cost objectives set forth in § 419.50(d)(1).

(c) The costs in each pool shall be allocated to those cost objectives in reasonable proportion to the beneficial or causal relationship of the pooled costs to those cost objectives.

§ 419.50 **Techniques for application.**

(a) *Number of pools.*—(1) A business unit may accumulate its overhead costs in a single pool unless it perform: (i) two or more productive functions (e.g., manufacturing, engineering or services), or (ii) a single productive function whose activities are performed in materially different proportions for the cost objectives among which the overhead costs are to be allocated.

(2) Overhead costs of a productive function may be accumulated in an individual overhead pool unless the function contains productive activities which are performed in materially different proportions for the cost objectives.

(3) Overhead costs of different productive activities within a productive function may be combined in a productive activity overhead pool(s) unless the productive activities to be combined are performed in materially different proportion for the cost objectives.

(4) Notwithstanding (1), (2), and (3) above, an additional overhead pool shall be required only if the creation of the additional pool would result in a materially different allocation of overhead costs to a significant contract subject to this Standard. A material difference occurs when the allocation to such contract by the addition of any pool differs by 5 percent or more from the amount that would otherwise be allocated to that contract.

(b) *Composition of a Pool.* (1) A pool of overhead costs shall include:

(i) All overhead costs specifically identified with a business unit, productive function, or productive activity or activities to which a pool relates;

(ii) Costs allocated from other indirect cost pools in accordance with 4 CFR Part 418, and

(iii) Expenses of a home office associated with a segment's overhead costs, except those identified as residual expenses in accordance with 4 CFR Part 403.40(c), the allocation of which is provided for in 4 CFR Part 410.

(2)(i) An overhead pool shall exclude the costs related to a special facility (e.g., wind tunnel, space chamber, and reactor) whose total operating costs is material unless the base used for allocating the pool reasonably represents the usage of such special facility by each cost objective. The costs of such facility shall be allocated in accordance with 4 CFR Part 418.

(ii) The costs related to a special facility, however, are required to be excluded from an overhead pool only if the allocation of such costs in accordance with 4 CFR Part 418 would result in a materially different allocation to a significant contract subject to this Standard. A material difference occurs when the allocation to such contract by the allocation of the costs of a special facility in accordance with 4 CFR Part 418 differs by 5 percent or more from the amount that otherwise would be allocated to that contract.

(3) Costs incurred for the common benefit of, or caused by, two or more overhead pools, such as costs of production management and production support, shall be allocated in accordance with 4 CFR Part 418.

(c) *Selection and Composition of Allocation Base.* The selection of a particular allocation base for any pool of overhead costs shall be guided by the criteria set forth below. The allocation base shall include all elements of the cost objectives listed in § 419.50(d)(1)(ii), (iii), (iv), (v) and (vi) which would be included as base elements in like circumstances for final cost objectives.

(1) *Direct Labor Hour or Direct Labor Cost.* (i) A direct labor hour base or a direct labor cost base shall be used, except as provided in (2) or (3) below. the determination as to which of these bases to use shall take into account whether the costs included in a pool are in the aggregate more likely to vary with direct labor hours or with direct labor costs.

(ii) A direct labor cost base shall exclude the premium portion of overtime pay and shift differential pay, and other special pay and allowances, such as hazardous duty pay and foreign duty pay.

(iii) A direct labor hour base or a direct labor cost base shall include the hours or labor costs of purchased labor, if a business unit uses a material amount of purchased labor, and if such labor performs work under the supervision and control of the business unit which is substantially similar to the work of the business unit's own direct labor employees; and uses the business unit's facilities and equipment in substantial performance of their work. Purchased labor shall be included in a direct labor cost base at a rate(s) equivalent to the labor costs of the business unit's own employees for similar labor classifications or the labor costs the business unit would pay if such employees were on its own payroll.

(iv) A direct labor hour base or a direct labor cost base shall exclude the hours or labor costs, where material in amount, of employees lent to other cost objectives of the business unit, to other segments, or to a home office. Conversely, a direct labor hour base or a direct labor cost base shall include the hours or labor costs, where material in amount, of employees borrowed from other cost objectives of the business unit, from other segments, or from a home office.

(2) *Direct Material Cost or Physical Characteristics of Direct Materials.* (i) A direct material cost base, as measured by 4 CFR 411.50 (a) and (b), or a base representing the physical characteristics of direct materials (e.g. number of units, weight or volume) shall be used for any separate material-related overhead pool. Such a base shall include purchased services where the services receive substantial benefit from or cause a substantial portion of such a pool. If the contracting parties agree on the value of customer furnished materials, such value may be included in a direct material cost base.

(ii) Where items are produced or worked on for stock or product inventory, the direct material costs of such items shall be included only once in the direct material cost base in the cost accounting period(s) in which such items are produced or worked on, and shall not be included in the base of another cost accounting period.

(3) *Machine Hour.* A machine hour base may be used if the overhead costs are comprised predominately of facility-related costs, such as depreciation, maintenance and utilities.

(d) *Allocation to Cost Objectives.* (1) Overhead costs shall be allocated to:

(i) Final cost objectives;

(ii) Goods produced for stock or product inventory;

(iii) Independent research and development and bid and proposal projects;

(iv) Cost centers used to accumulate costs identified with a process cost system (i.e., process cost centers);

(v) Goods or services produced or acquired for other segments of the contractor and for other cost objectives of a business unit; and

(vi) Self-construction, fabrication, betterment, improvement, or installation of tangible capital assets.

(2) Where a particular cost objective in relation to other cost objectives receives significantly more or less benefit from overhead costs than would be reflected by the allocation of such costs using a base determined pursuant to paragraph (c) of this section, the Government and contractor may agree to a special allocation from the applicable overhead pool(s) to the particular cost objective commensurate with the benefits received. The amount of a special allocation to any such cost objective made pursuant to such an agreement shall be excluded from the overhead pool(s) and the particular cost objective's allocation base data shall be excluded from the base used to allocate the pool(s).

(e) *Use of Pre-established Rates for Overhead Costs.* (1) Pre-established rates, based on either forecasted actual or standard costs, may be used in allocating an overhead pool. Where variances of a cost accounting period are material, these variances shall be disposed of by allocating them to benefiting cost objectives in proportion to the costs previously allocated to these cost objectives.

(2) Where pre-established rates are used to allocate the costs of an overhead pool, these rates shall reflect the costs and activities anticipated for the cost accounting period. Such pre-established rates shall be reviewed at least annually, and revised as necessary to reflect the anticipated conditions.

(3) Pre-established rates used for allocating overhead pools may be revised during a cost accounting period.

(i) The revised rates shall reflect the costs and activities anticipated for the entire cost accounting period.

(ii) If the accumulated variances are significant, the costs previously allocated shall be adjusted to the amount which would have been allocated using the revised pre-established rates.

§ 419.60 Illustrations.

(a) Business Unit A maintains a single overhead pool. Business Unit A has substantial amounts of supply contracts as well as substantial amounts of R&D contracts and maintains a manufacturing department and an engineering department. An analysis indicates that the amount of overhead costs allocated to Contract XYZ, a significant contract, by its single pool is $2,000,000, whereas the amount that would be allocated to it using two separate productive function pools (one for manufacturing and one for engineering) would be $2,090,000; the difference being 4.5 percent ($90,000÷$2,000,000). Under this circumstance, Business Unit A may continue to maintain its single overhead pool in accordance with § 419.50 (a)(4).

(b) Business Unit B, performing significant machining and assembling activities on a number of contracts, maintains a single manufacturing overhead pool for these activities. The machining and assembling activities are performed in materially different proportions for the contracts in that machining activity is performed for all contracts, while the assembling activity is performed for only some contracts. An analysis indicates that the amount of overhead costs allocated to Contract XYZ, a significant contract, by its manufacturing overhead pool is $500,000, whereas, the amount that would be allocated to it using two separate productive activity pools (one for machining activity and one for assembling activity) would be $450,000; the difference being 10 percent ($50,000÷$500,000). Under this circumstance Business Unit B must establish separate productive activity pools in accordance with § 419.50(a)(2) and (4).

(c) Business Unit C performs five significant productive activities in its engineering department. Business Unit C, however, maintains two productive activity pools; one pool which combines the overhead costs of four productive activities which are performed in about the same proportions for its contracts, and another pool for a productive activity which is performed only for some contracts. Business Unit C's two pools would be in accordance with § 419.50(a)(3).

(d) Business Unit D, whose cost accounting period is the calendar year, performed significant amounts of overtime work on certain government contracts in May and June and on certain commercial work in July and August. This overtime work was necessary to meet an accelerated delivery schedule at the specific request (and Business Unit D had obtained the approval) of government and commercial customers. Business Unit D allocates its overhead costs on a direct labor cost base, and charges the premium portion of the overtime pay directly to the applicable government and commercial contracts as part of the direct labor costs. In accordance with § 419.50(c)(1)(ii), Business Unit D must exclude the premium portion of the overtime pay from the direct labor cost allocation base.

Assume the same facts as above, except that Business Unit D uses the direct labor hour allocation base and incurred 30,000 hours of overtime work for which the employees are to be paid at a time-and-a-half rate. In accordance with § 419.50(c)(1)(ii), Business Unit D should include 30,000 hours in the allocation base (on a straight-time basis), not 45,000 hours.

(e) Business Unit E maintains a single engineering overhead pool for the engineering work being performed at its principal place of business and for engineering work at location X. Employees working at location X are paid a special duty pay, which is material in amount. Business Unit E uses the direct labor cost base for allocating the overhead pool and includes the costs of the special duty pay in the allocation base. In accordance with § 419.50(c)(1)(ii), Business Unit E must exclude the special duty pay from the direct labor cost allocation base.

(f) Business Unit F, which uses the direct labor hour base to allocate its overhead pool, uses a significant amount of purchased labor under the conditions described in § 419.50(c)(1)(iii). Business Unit F does not include the hours worked by purchased labor in its direct labor hour allocation base. This practice is not in accordance with the above cited provisions, and Business Unit F must include the hours worked by the purchased labor in the direct labor hour allocation base.

Assume the same facts as above except that Business Unit F uses the direct labor cost allocation base and treats the cost of purchased labor as "other direct costs." Business Unit F must include the equivalent labor costs of the purchased labor in the allocation base in accordance with the cited provisions.

(g) Business Unit G has a machining activity for which it develops a separated overhead rate, using the direct labor cost as the allocation base. The machining activity occasionally does significant amounts of work for other departments of the Business Unit, such as fabricating tools for the tool room. The labor used in doing the work for other departments is of the same nature as that used for contract work. However, the machining labor for other departments is not included in the base used to allocate the overhead costs of the machining activity. In accordance with § 419.50(c) and § 419.50(d)(1)(v), Business Unit G must include the cost of labor doing work for the other departments in the allocation base for the machining activity overhead pool.

§ 419.70 Exemptions.

None for this Standard,

§ 419.80 Effective date.

(a) The effective date of this Standard is [reserved].

(b) This Standard shall be followed by each contractor on or after the start of his next Cost Accounting period beginning after the receipt of a contract to which this Cost Accounting Standard is applicable.

Dated: July 18, 1979.

Arthur Schoenhaut,

Executive Secretary.

[FR Doc. 79-22706 Filed 7-20-79; 8:45 am]

BILLING CODE 1620-01-M

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

[7 CFR Part 967]

Celery Grown in Florida; Proposed Handling Regulation

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Proposed rule.

SUMMARY: This proposed regulation would establish the quantity of Florida celery to be marketed fresh during the 1979-80 season, with the objective of assuring adequate supplies and orderly marketing.

DATE: Comments due August 3, 1979.

ADDRESSES: Comments should be sent to: Hearing Clerk, Room 1077-S, U.S. Department of Agriculture, Washington, D.C. 20250. Two copies of all written comments shall be submitted, and they will be made available for public inspection at the office of the Hearing Clerk during regular business hours.

FOR FURTHER INFORMATION CONTACT: Donald S. Kuryloski, Acting Deputy Director, Fruit and Vegetable Division, AMS, U.S. Department of Agriculture, Washington, D.C. 20250. Telephone: (202) 447-6393.

SUPPLEMENTARY INFORMATION: Marketing Agreement No. 149 and Order No. 967, both as amended (7 CFR 967) regulate the handling of celery grown in Florida. It is effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601-674). The Florida Celery Committee, established under the order, is responsible for local administration.

This notice is based upon the unanimous recommendations made by the committee at its public meeting in Orlando on June 13.

The committee recommended a preliminary Marketable Quantity of approximately 9.6 million crates of fresh celery for the 1979-80 season. This recommendation is based on the appraisal of the expected supply and prospective market demand.

The recommended 9.6 million crate Marketable Quantity is 20 percent more than the approximately 8 million crates expected to be marketed during the current season ending July 31, 1979. Each producer registered pursuant to § 967.37(f) would have an allotment equal to 100 percent of his historical marketings. This recommendation provides the industry an opportunity to (1) produce to its fullest capacity for the benefit of the consumer, and (2) determine its actual or potential maximum production capacity.

As required by § 967.37(d)(1) a reserve of six percent of the 1978-79 total Base Quantities is authorized for new producers and for increases by existing producers, with 279,705 crates to be allotted to each category. Four producers submitted applications for additional Base Quantities for use only one season. However, pursuant to § 967.151 (43 FR 15608) the committee denied such applications since under the formula set forth in § 967.155 (43 FR 57239), Base Quantities for the applicants would be increased a total of 512,243 crates.

To maximize the benefits of orderly marketing the proposed regulation should become effective as early as possible in August, when the marketing year begins. Interested persons were given an opportunity to comment on the proposal at an open public meeting on June 13, where it was unanimously recommended by the committee. This proposal is similar to regulations in effect for past seasons. It is hereby determined that the period allowed for comments should be sufficient under these circumstances and will effectuate the declared policy of the act.

On the basis of all considerations it is further determined that this proposed regulation would tend to effectuate the declared policy of the act.

The proposal is as follows:

§ 967.315 Handling regulation; marketable quantity; and uniform percentage for the 1979-80 season beginning August 1, 1979.

(a) The Marketable Quantity established under § 967.36(a) is 9,644,484 crates of celery.

(b) As provided in § 967.38(a), the Uniform Percentage shall be 100 percent.

(c) Pursuant to § 967.36(b), no handler shall handle any harvested celery unless it is within the Marketable Allotment of a producer who has a Base Quantity and such producer authorizes the first handler thereof to handle it.

(d) As required by § 967.37(d)(1) a reserve of six percent of the total Base Quantities is hereby authorized for (1) new producers and (2) increases for existing Base Quantity holders, with 279,705 crates allotted to each category.

(e) Terms used herein shall have the same meaning as when used in the said marketing agreement and order.

Note.—This proposal has been reviewed under the USDA criteria implementing Executive Order 12044. A determination has been made that this action should not be classified "significant." An Impact Analysis is available from Peter G. Chapogas (202) 447-5432.

Dated: July 17, 1979.

D. S. Kuryloski,

Acting Deputy Director, Fruit and Vegetable Division, Agricultural Marketing Service.

[FR Doc. 79-22640 Filed 7-20-79; 8:45 am]

BILLING CODE 3410-02-M

Office of the Secretary

[7 CFR Parts 2900, 2901]

Proposed Rulemaking Regarding Administrative Procedures for Adjustments of Natural Gas Curtailment Priority Regulations

AGENCY: Office of the Secretary, USDA.

ACTION: Proposed rule.

SUMMARY: The Office of the Secretary, United States Department of Agriculture is publishing for public comment a proposed rule providing administrative procedures for the making of certain adjustments to its Essential Agricultural Uses and Requirements regulations in Part 2900 of Chapter XXIX of Title 7, Code of Federal Regulations. The proposed rule establishes procedures as required by section 502 of the Natural Gas Policy Act of 1978, including an opportunity for the oral presentation of data, views, and arguments which would be used in conjunction with requests for interpretations, modifications, or rescissions necessary to prevent special hardship, inequity, or an unfair distribution of burdens.

DATES: Written comments are due by 4:30 p.m., August 22, 1979.

ADDRESS: All written comments should be sent to Weldon V. Barton, Director, Office of Energy, USDA, Room 226-E Administration Building, United States Department of Agriculture, 14th and Independence Avenue, SW., Washington, D.C. 20250.

FOR FURTHER INFORMATION CONTACT: Weldon V. Barton, Director, Office of Energy, USDA, Room 226-E Administration Building, 14th and Independence Avenue, SW., Washington, D.C. 20250, telephone number: (202) 447-2455.

SUPPLEMENATRY INFORMATION:

I. Background.
II. Description of Proposal.
III. Public Comment and Hearing Procedures.

I. Background

Section 502 of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621, 92 Stat. 3350) requires the Secretary of Agriculture to prescribe a rule which provides for the making of "adjustments" for rules issued by the Secretary of Agriculture under the NGPA, as may be necessary to prevent special hardship, inequity, or unfair distribution of burdens.

Under section 401 of the NGPA, the Secretary of Agriculture was required to certify essential agricultural uses of natural gas and the amounts of natural gas required for such essential agricultural uses in order to meet full food and fiber production. A final rule containing such certifications was issued by the Secretary of Agriculture on May 17, 1979 (44 FR 28782).

II. Description of Proposal

Section 502 of the NGPA requires that administrative procedures be established which are available to any person for the purpose of seeking an interpretation, modification, or rescission of, exception to or exemption from rules issued under the NGPA. This proposed rule provides procedures for seeking interpretations, modifications, or rescissions of the Secretary of Agriculture's Essential Agricultural Uses and Requirements regulations in 7 CFR Part 2900 and any subsequent rules that may be issued to implement the Secretary of Agriculture's responsibilities under section 401 of the NGPA.

The proposed rule does not provide procedures for acting on requests for exceptions to or exemptions from the Secretary of Agriculture's Essential Agricultural Uses and Requirements regulation, since procedures for seeking interpretations, modifications, or rescissions are considered to cover the range of requests appropriate to the Secretary of Agriculture's responsibilities under section 401 of the NGPA. Exceptions to or exemptions from the agricultural curtailment priority structure are considered to be more properly addressed to the Federal Energy Regulatory Commission (FERC) which implements curtailment priorities. All such requests should therefore be filed with the FERC in accordance with its applicable administrative procedures. Requests for review of a denial of an exception or exemption should likewise be filed with FERC.

Section 502 of the NGPA requires the Secretary of Agriculture to provide an opportunity for oral presentation of views when considering requests for adjustment. Section 2901.3 of the proposed rule implements this statutory requirement by granting an opportunity for oral presentation of data, views and argument in support of any person's request for an interpretation, modification, or rescission, if the request for an oral presentation is made in writing and submitted with the request for adjustment.

Sections 2901.4(a) and 2901.5(a) propose that requests for adjustments be filed with the Director of the Office of Energy of the Department of Agriculture. In order to provide for expeditious administrative processing, the rule describes the circumstances under which a request to the Director, Office of Energy, for adjustment, is considered denied. Requests for review of such denials are to be made to the Secretary of Agriculture and acted upon before a denial is considered final agency action for purposess of judicial review.

Section 2901.5 proposes that a request for modification or rescission be treated as a petition for a rulemaking. The Director may respond by either: (1) instituting rulemaking procedures, (2) notifying the petitioner that he does not intend to institute rulemaking procedures and stating the reasons; or (3) notifying the petitioner in writing of the circumstances making it inappropriate to make a decision at that time. Because of the desire to keep administrative procedure rules in this code section and since § 2901.5 addresses requests for amendments, 7 CFR 2900.5 is proposed to be deleted.

III. Public Written Comment Procedures

The public is invited to participate in any aspect of this rulemaking by submitting data, views, or arguments with respect to the proposals set forth in this rulemaking.

Written comments must be submitted by 4:30 p.m., August 22, 1979, to the address indicated in the "Addresses" section of this preamble, and should be identified on the outside envelope and on the document with the designation: "Part 2901—Administrative Procedures." Five copies should be submitted. All comments received will be available for public inspection in Room 5173 South Building, 12th and Independence Avenue, SW., Washington, D.C. 20250 between the hours of 9:00 a.m. and 4:00 p.m., Monday through Friday. All comments received by 4:30 p.m., August 22, 1979, and all other relevant information will be considered by the Secretary of Agriculture before final action is taken on this proposed regulation.

This proposed rule has been classified as not significant and is being published under emergency procedures, as authorized by Executive Order 12044 and Secretary's Memorandum No. 1955, without a full 60-day comment period. It has been determined by Weldon Barton, Director, Office of Energy, USDA that an emergency situation exists which warrants less than a full 60-day comment period, as it is expected that a number of petitions will be received subsequent to the promulgation of this rule. A full 60-day comment period on the proposed procedural rule would not allow an adequate period for subsequent filing of petitions, and careful consideration and ruling thereon, by the USDA prior to November 1, 1979—the advent of natural gas curtailments in the winter heating season. The substantive rules for which this procedural rule will apply were adopted to meet a statutory deadline. Requests for adjustment of the substantive rules are currently being received, and it is believed a 30-day comment period for this procedural rule will be in the public interest.

Any information or data submitted which is considered by the party who submitted it to be confidential must be so identified and submitted in writing, one copy only. The Secretary reserves the right to determine the confidential status of the information or data and to treat it accordingly.

In consideration of the foregoing, it is proposed to amend Chapter XXIX of Title 7, Code of Federal Regulations as set forth below:

PART 2900—ESSENTIAL AGRICULTURAL USES AND VOLUMETRIC REQUIREMENTS—NATURAL GAS POLICY ACT

§ 2900.5 [Deleted]

1. Part 2900 of Chapter XXIX of Title 7, Code of Federal Regulations, is amended by deleting § 2900.5 thereof.

2. Chapter XXIX of Title 7, Code of Federal Regulations, is amended by adding a Part 2901 to read as follows:

PART 2901—ADMINISTRATIVE PROCEDURES

Authority: Secs. 502, 506, Pub. L. 95–621, 92 Stat. 3397, 3405, November 9, 1978.

§ 2901.1 Purpose and scope.

The purpose of this Part 2901 is to provide procedures for the making of certain adjustments to the Secretary of Agriculture's Essential Agricultural Uses and Requirements regulations in accordance with Section 502(c) of the Natural Gas Policy Act of 1978, in order to prevent special hardship, inequity, or an unfair distribution of burdens. The procedures in this Part 2901 apply to any person seeking an interpretation, modification, or rescission of the Essential Agricultural Uses and Requirements regulations in Part 2900 of Chapter XXIX. This Part 2901 does not include procedures for exceptions or exemptions because such adjustments are inapplicable to the Essential Agricultural Uses and Requirements regulations.

§ 2901.2 Definitions.

(a) "Person" means any individual, firm, sole proprietorship, partnership, association, company, joint venture or corporation.

(b) "Director" means the Director of the Office of Energy, U.S. Department of Agriculture.

(c) "Secretary" means the Secretary of the U.S. Department of Agriculture.

(d) "Adjustment" means an interpretation, modification, or rescission of, the Essential Agricultural Uses and Requirements Regulations, Part 2900 hereof.

(e) "NGPA" means the Natural Gas Policy Act of 1978, Pub. L. 95–621.

(f) "Petitioner" means any person seeking an adjustment under this Part 2901.

§ 2901.3 Oral presentation.

Any person seeking an adjustment under this Part 2901 shall be given an opportunity to make an oral presentation of data, views and arguments in support of the request for an adjustment, provided that a request to make an oral presentation is submitted in writing with the request for the adjustment.

§ 2901.4 Interpretation.

(a) *Request for an Interpretation.* (1) Any person seeking an interpretation of the Essential Agricultural Uses and Requirements regulations in Part 2900 shall file a formal written request with the Director. The request should contain a full and complete statement of all relevant facts pertaining to the circumstance, act or transaction that is the subject of the request and to the action sought, and should state the special hardship, inequity, or unfair distibution of burdens that will be prevented by the interpretation sought and why the interpretation is consistent with the purposes of NGPA.

(2) If the petitioner wishes to claim confidential treatment for any information contained in the request or other document submitted under this Part 2901, such person shall file together with the document a second copy of the document from which has been deleted the information for which such person wishes to claim confidential treatment. The petitioner shall indicate in the original document that it is confidential or contains confidential information and may file a statement specifying the justification for non-disclosure of the information for which non-disclosure is sought. The Director shall consider such requests, and subject to the Freedom of Information Act, 5 U.S.C. 552 and other applicable laws and regulations, shall treat such information as confidential.

(b) *Investigations.* The Director may initiate an investigation of any statement in a request and utilize in his evaluation any relevant facts obtained in such investigation. The Director may accept submissions from third persons relevant to any request for interpretation provided that the petitioner is afforded an opportunity to respond to all such submissions. In evaluating a request for interpretation, the Director may consider any other source of information.

(c) *Applicability.* Any interpretation issued hereunder shall be issued on the basis of the information provided in the request, as supplemented by other information brought to the attention of the Director during the consideration of the request. The interpretation shall, therefore, depend for its authority on the accuracy of the factual statement and may be relied upon only to the extent that the facts of the actual situation correspond to those upon which the interpretation was based.

(d) *Issuance of an Interpretation.* Upon consideration of the request for interpretation and other relevant information received or obtained by the Director, the Director may issue a written interpretation. A copy of the written interpretation shall be provided to FERC and the Secretary of Energy.

(e) *Denial of an Interpretation.* An interpretation shall be considered denied for purpose of review of such denial under Section 2901.6 only if:

(1) The Director notifies the petitioner in writing that the request is denied and that an interpretation will not be issued; or

(2) The Director does not respond to a request for an interpretation, by (i) issuing an interpretation, or (ii) giving notice of when an interpretation will be issued within 45 days of the date of receipt of the request, or within such extended time as the Director may prescribe by written notice within the 45-day period.

§ 2901.5 Modification or rescission.

(a) *Request for modification or rescission.* (1) Any person seeking a modification or a rescission of the Essential Agricultural Uses and Requirements regulation of Part 2900 shall file a formal written request with the Director. The request shall contain a full and complete statement of all relevant facts pertaining to the circumstance, act or transaction that is the subject of the request and to the action sought. The request should state the special hardship, inequity or unfair distribution of burdens that will be prevented by making the modification or rescission.

(2) If the petitioner wishes to claim confidential treatment for any information contained in the request or other document submitted under this Part 2901, such person shall file together with the document a second copy of the document from which has been deleted the information for which such person wishes to claim confidential treatment. The petitioner shall indicate in the orginal document that it is confidential or contains confidential information and may file a statement specifying the justification for non-disclosure of the information for which non-disclosure is sought. The Director shall consider such requests, and, subject to the Freedom of Information Act, 5 U.S.C. 552 and other

applicable laws and regulations, shall treat such information as confidential.

(3) The request shall be filed as a petition for rulemaking and treated in accordance with the procedures, as applicable, of 7 CFR Part 1, Subpart B.

(b) *Institution of Rulemaking.* Upon consideration of the request for modification or rescission and other relevant information received or obtained by the Director, the Director may institute rulemaking proceedings in accordance with the Administrative Procedures Act 5 U.S.C. 551 *et seq.* and applicable regulations.

(c) *Denial of a modification or rescission.* If the Director (1) denies the request for modification or rescission in writing by notifying the petitioner that he does not intend to institute rulemaking proceedings as proposed and stating the reasons therefor, or (2) does not respond to a request for a modification or rescission in accordance with paragraph (b) of this section or (3) notifies the petitioner in writing that the matter is under continuing consideration and that no decision can be made at that time because of the inadequacy of available information, changing circumstances or other reasons as set forth therein, within 45 days of the date of the receipt thereof, or within such extended time as the Director may prescribe by written notice within that 45-day period, the request shall be considered denied for the purpose of review of such denial under § 2901.6.

§ 2901.6 Review of denials.

(a) *Request for Review.* (1) Any person aggrieved or adversely affected by a denial of a request for any interpretation under § 2901.4 may request a review of the denial by the Secretary within 30 days from the date of the denial.

(2) Any person aggrieved or adversely affected by a denial of a request for a modification or rescission under § 2901.5, may request a review of the denial by the Secretary within 30 days from the date of the denial.

(b) *Procedures.* Any request for review under § 2901.6(a) shall be in writing and shall set forth the specific ground upon which the request is based. There is no final agency action for purposes of judicial review under § 2901.7 until that request has been acted upon. If the request for review has not been acted upon within 30 days after it is received, the request shall be deemed to have been denied. That denial shall then constitute final agency action for the purpose of judicial review under § 2901.7.

§ 2901.7 Judicial review.

Any person aggrieved or adversely affected by a final agency action taken on a request for an adjustment under this section may obtain judicial review in accordance with Section 506 of the Natural Gas Policy Act of 1978.

Environmental and Regulatory Analysis

After reviewing this proposed regulation pursuant to USDA's responsibilities under the National Environmental Policy Act of 1969, Pub. L. 91–190, 83 Stat. 852 (42 U.S.C. 4321), the USDA has determined the proposed action does not constitute a major Federal action significantly affecting the quality of the human environment. Therefore, the USDA has determined no environmental impact statement is required for the proposed regulation. A copy of the finding of no significant impact and environmental assessment is available for inspection and copying in Room 5173 South Building, 12th and Independence, SW., U.S. Department of Agriculture, Washington, D.C. 20250.

The USDA has also determined this proposed regulation is not significant within the meaning of USDA's procedures to implement Executive Order 12044 on "Improving Government Regulations" (42 FR 12661, March 24, 1978). This is a procedural rule and is not expected to affect important national energy policy concerns, have adverse effects with respect to employment, economic growth, the ability of consumers to have adequate energy supplies at reasonable prices, or have more than a minimal effect on State and local governments. Hence, the preparation of a regulatory analysis is not required.

Dated: July 18, 1979.

Bob Bergland,

Secretary.

[FR Doc. 79-22821 Filed 7-20-79; 8:45 am]

BILLING CODE 3410-01-M

NATIONAL CREDIT UNION ADMINISTRATION

[12 CFR Part 742]

Liquidity Reserves of Insured Credit Unions; Extension of Comment Period

AGENCY: National Credit Union Administration.

ACTION: Extension of Comment Period.

SUMMARY: The National Credit Union Administration extends, until August 10, 1979, the comment period on its proposed regulation "Liquidity Reserves of Insured Credit Unions" (published at 44 FR 33094). Certain commenters have requested this action, which will provide all commenters with additional time to formulate and present their views on the proposed regulation.

DATES: Comments on the proposed regulation should be forwarded to Robert S. Monheit, Senior Attorney, Office of General Counsel, National Credit Union Administration, 2025 M Street, NW, Washington, DC 20456, to be received on or before August 10, 1979.

ADDRESS: National Credit Union Administration, 2025 M Street, N.W., Washington, D.C., 20456.

FOR FURTHER INFORMATION CONTACT: Robert H. Dugger, Acting Director, Policy Analysis Office, 1375 K Street, NW, or Robert M. Fenner, Assistant General Counsel, Office of General Counsel, at 2025 M Street, NW. Telephone: (202) 633–6775 (Mr. Dugger), (202) 632–4870 (Mr. Fenner).

SUPPLEMENTARY INFORMATION: On June 8, 1979, the National Credit Union Administration (NCUA) issued a proposed regulation entitled "Liquidity Reserves of Insured Credit Unions." The proposal was codified at 12 CFR Part 742, and published at 44 FR 33094. The proposal would require that each insured credit union maintain a liquidity reserve of specified assets. The minimum amount of these assets would be 5% of the total of the credit union's member accounts and notes payable. The assets would be available to meet member demands for share withdrawals. The proposal was made as a result of recent substantial declines in credit union liquidity and capital, as discussed both in the "supplementary information" portion of the published proposal and in the Administration "draft regulatory analysis" concerning the proposal. (The draft analysis is available upon request.)

Public participation in this proposed regulation is being requested in the form of written comments. The proposal initially provided that such comments would be received until July 25, 1979. Inasmuch as the proposed regulation would apply to federally insured State chartered credit unions as well as all Federal credit unions, the National Association of State Credit Union Supervisors (NASCUS) has requested that the Administration extend the comment period, so as to afford NASCUS sufficient time to poll its membership and present representative views. Other prospective commenters have requested additional time to formulate and present their views. The Administration believes these requests are reasonable, and that an addition of approximately 15 days to the comment period will not seriously hamper the Agency's consideration of this matter. Accordingly, the public comment period on NCUA's proposed regulation "Liquidity Reserves of Insured Credit Unions" (12 CFR Part 742) is hereby extended until August 10, 1979.

(12 U.S.C. 1762(b), 12 U.S.C. 1766(a), 12 U.S.C. 1781(b)(6).)

Lawrence Connell,

Chairman.

July 18, 1979.

[FR Doc. 79-22707 Filed 7-20-79; 8:45 am]

BILLING CODE 7535-01-M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

[14 CFR Ch. I]

[Summary Notice No. PR-79-3A]

Petitions for Rulemaking; Summary of Petitions Received and Dispositions of Petitions Denied

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of petitions for rulemaking and of dispositions of petitions denied.

SUMMARY: Pursuant to FAA's rulemaking provisions governing the application, processing, and disposition of petitions for rulemaking (14 CFR Part 11), this notice contains a summary of certain petitions requesting the initiation of rulemaking procedures for the amendment of specified provisions of the Federal Aviation Regulations and of denials of certain petitions previously received. The purpose of this notice is to improve the public's awareness of this aspect of FAA's regulatory activities. Publication of this notice and any information it contains or omits is not intended to affect the legal status of any petition or its final disposition.

DATES: Comments on petitions received must identify the petition docket number involved and be received on or before: August 15, 1979.

ADDRESSES: Send comments on the petition in triplicate to: Federal Aviation Administration, Office of the Chief Counsel, Attn: Rules Docket (AGC-24), Petition Docket No. , 800 Independence Avenue, SW., Washington, D.C. 20591.

FOR FURTHER INFORMATION: The petition, any comments received, and a copy of any final disposition are filed in the assigned regulatory docket and are available for examination in the Rules Docket (AGC-24), Room 916, FAA Headquarters Building (FOB 10A), Federal Aviation Administration, 800 Independence Avenue, SW., Washington, D.C. 20591; telephone (202) 426-3644.

This notice is published pursuant to paragraphs (b) and (f) of § 11.27 of Part 11 of the Federal Aviation Regulations (14 CFR Part 11).

Issued in Washington, D.C. on July 17, 1979.

Edward P. Faberman,

Acting Assistant Chief Counsel, Regulations and Enforcement Division.

Petitions for Rulemaking

Docket No.	Petitioner	Description of the Rule Requested
17320	National Federation of the Blind.	To amend Parts 121 and 123 to delete those requirements affecting a blind person's ability to carry on board an aircraft canes and certain other items. Comment period extended to August 15, 1979.

[FR Doc. 79-22687 Filed 7-20-79; 8:45 am]

BILLING CODE 4910-13-M

[14 CFR Part 71]

[Airspace Docket No. 79-RM-20]

Alteration of Transition Areas

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: This Notice of Proposed Rulemaking (NPRM) proposes to alter the Dickinson, North Dakota 700' and 1,200' transition areas to provide controlled airspace for aircraft executing the new VOR/DME Runway 35, standard instrument approach procedure developed for Dickinson Municipal Airport, Dickinson, North Dakota.

DATES: Comments must be received on or before August 12, 1979.

ADDRESSES: Send comments on the proposal to: Chief, Air Traffic Division, Attn: ARM-500, Federal Aviation Administration, 10455 East 25th Avenue, Aurora, Colorado 80010.

A public docket will be available for examination by interested persons in the office of the Regional Counsel, Federal Aviation Administration, 10455 East 25th Avenue, Aurora, Colorado 80010.

FOR FURTHER INFORMATION CONTACT: Pruett B. Helm, Airspace and Procedures Specialist, Operations, Procedures and Airspace Branch (ARM-530), Air Traffic Division, Federal Aviation Administration, Rocky Mountain Region, 10455 East 25th Avenue, Aurora, Colorado 80010; telephone (303) 837-3937.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested persons may participate in the proposed rulemaking by submitting such written data, views, or arguments as they may desire. Communications should be submitted in triplicate to the Chief, Air Traffic Division, Federal Aviation Administration, 10455 East 25th Avenue, Aurora, Colorado 80010. All communications received will be considered before action is taken on the proposed amendment. No public hearing is contemplated at this time, but arrangements for informal conferences with Federal Aviation Administration officials may be made by contacting the Regional Air Traffic Division Chief. Any data, views, or arguments presented during such conferences must also be submitted in writing in accordance with this notice in order to become part of the record for consideration. The proposal contained in this noice may be changed in the light of comments received.

Availability of NPRM

Any person may obtain a copy of this Notice of Proposed Rulemaking (NPRM) by submitting a request to the Federal Aviation Administration, Office of Public Affairs, Attention: Public Information Center, APA-430, 800 Independence Avenue, SW., Washington, DC 20591, or by calling (202) 426-8058. Communications must identify the notice number of this NPRM. Persons interested in being placed on a mailing list for future NPRM's should also request a copy of Advisory Circular No. 11-2 which describes the application procedure.

The Proposal

The Federal Aviation Administration is considering an amendment to Subpart G of Part 71 of the Federal Aviation Regulations (14 CFR Part 71) to alter the Dickinson, North Dakota 700' and 1,200' transition areas. The present transition areas are inadequate in size to contain the new VOR/DME Runway 35 standard instrument approach procedure developed for Dickinson Municipal Airport, Dickinson, North Dakota. It is proposed to make the alteration of the transition areas effective to coincide with the effective date of the new standard instrument approach.

Accordingly, the Federal Aviation Administration proposes to amend Subpart G of Part 71 of the Federal Aviation Regulations (14 CFR Part 71) as follows:

By amending § 71.181 so as to alter the following transition areas to read:

Dickinson, N. Dak.

That airspace extending upward from 700' above the surface within a 9.5 mile radius of the Dickinson Municipal Airport (latitude 46°47'45" N., longitude 102°48'00" W.) and that airspace extending upward from 1,200' above the surface within a 22 mile radius of the Dickinson VORTAC (latitude 46°51'36" N., longitude 102°46'23" W.) extending clockwise from the Dickinson VORTAC 214° radial to the Dickinson VORTAC 093° radial.

Drafting Information

The principal authors of this document are Pruett B. Helm, Air Traffic Division, and Daniel J. Peterson, office of the Regional Counsel, Rocky Mountain Region.

(Sec. 307(a), Federal Aviation Act of 1958, as amended, (49 U.S.C. 1348(a)), sec. 6(c) of the Department of Transportation Act (49 U.S.C. 1655(c)))

Note.—The FAA has determined that this document involves a proposed regulation which is not significant under Executive Order 12044, as implemented by DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979). Since this regulatory action involves an established body of technical requirements for which frequent and routine amendments are necessary to keep them operationally current and promote safe flight operations, the anticipated impact is so minimal that this action does not warrant preparation of a regulatory evaluation, and a comment period of less than 45 days is appropriate.

Issued in Aurora, Colo., on July 13, 1979.

L. R. Robison,

Acting Director, Rocky Mountain Region.

[FR Doc. 79-22673 Filed 7-20-79; 8:45 am]

BILLING CODE 4910-13-M

[14 CFR Part 71]

[Airspace Docket No. 79-SO-45]

Extension of Victor Airway

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: This notice proposes to extend V-259 from Fort Mill, S.C., to Grand Strand, S.C. Aircraft are normally routed along this route to avoid traffic in the Florence, S.C. area and the Gamecock Military Operations Area (MOA). This amendment would reduce controller workload and aid flight planning.

DATES: Comments must be received on or before August 22, 1979.

ADDRESSES: Send comments on the proposal in triplicate to: Director, FAA Southern Region, Attention: Chief, Air Traffic Division, Docket No. 79-SO-45, Federal Aviation Administration, P.O. Box 20636, Atlanta, Ga. 30320.

The official docket may be examined at the office of the Regional Air Traffic Division.

FOR FURTHER INFORMATION CONTACT: Mr. Lewis W. Still, Airspace Regulations Branch (AAT-230), Airspace and Air Traffic Rules Division, Air Traffic Service, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, D.C. 20591; telephone: (202) 426-8525.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested persons may participate in the proposed rulemaking by submitting such written data, views or arguments as they may desire. Communications should identify the airspace docket number and be submitted in triplicate to the Director, Southern Region, Attention: Chief, Air Traffic Division, Federal Aviation Administration, P.O. Box 20636, Atlanta, Ga. 30320. All communciations received on or before August 22, 1979, will be considered before action is taken on the proposed amendment. The proposal contained in this notice may be changed in the light of comments received. All comments submitted will be available, both before and after the closing date for comments, in the Rules Docket for examination by interested persons.

Availability of NPRM

Any person may obtain a copy of this notice of proposed rulemaking (NPRM) by submitting a request to the Federal Aviation Administration, Office of Public Affairs, Attention: Public Information Center, APA-430, 800 Independence Avenue, SW., Washington, D.C. 20591, or by calling (202) 426-8058. Communications must identify the docket number of this NPRM. Persons interested in being placed on a mailing list for future NPRMs should also request a copy of Advisory Circular No. 11-2 which describes the application procedures.

The Proposal

The FAA is considering an amendment to § 71.123 of Part 71 of the Federal Aviation Regulations (14 CFR Part 71) to extend V-259 from Fort Mill, S.C. to Grand Strand, S.C., via Chesterfield, S.C. and Florence, S.C. This action would improve traffic flow in the Florence area, reduce controller workload and aid flight planning. This airway extension would also provide routing to avoid the Gamecock Military Operations Area (MOA) located such of Chesterfield.

The Proposed Amendment

Accordingly, pursuant to the authority delegated to me, the Federal Aviation Administration proposes to amend § 71.123 of Part 71 of the Federal Aviation Regulations (14 CFR Part 71) as republished (44 FR 307) as follows:

V-259 is amended to read as follows:

V-259. From Grand Strand, S.C., via Florence, S.C.; Chesterfield, S.C.; Fort Mill, S.C.; to Holston Mountain, Tenn.

(Secs. 307(a), 313(a), Federal Aviation Act of 1958 (49 U.S.C. 1348(a) and 1354(a)); sec. 6(c), Department of Transportation Act (49 U.S.C. 1655(c)); and 14 CFR 11.65)

Note.—The FAA has determined that this document involves a proposed regulation which is not significant under Excectuve Order 12044, as implemented by DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979). Since this regulatory action involves an established body of technial requirements for which frequent and routine amendments are necessary to keep them operationally current and promote safe flight operations, the anticipated impact is so minimal that this action does not warrant preparation of a regulatory evaulation and a comment period of less than 45 days is appropriate.

Issued in Washington, D.C., on July 16,1979.

B. Keith Potts,

Acting Chief, Airspace and Air Traffic Rules Division.

[FR Doc. 79-22674 Filed 7-20-79; 8:45 am]

BILLING CODE 4910-13-M

[14 CFR Part 73]

[Airspace Docket No. 78-SO-80]

Alteration of Restricted Areas

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: This notice proposes to extend Dare County, N.C., restricted areas 5314 G, H, and J northward a distance of two miles or less to contain the turning radius and run in tracks of high perfomance military aitcraft using targets within the R-5314 subareas. This

action would provide for the safe and efficient use of the navigable airspace in this area.

DATES: Comments must be received on or before August 22, 1979.

ADDRESSES: Send comments on the proposal in triplicate: Director, FAA Southern Region, Attention: Chief, Air Traffic Division, Docket No. 78-SO-80, P.O. Box 20636, Atlanta, Ga. 30320.

The official docket may be examined at the following location: FAA Office of the Chief counsel, Rules Docket (AGC-24), Room 916, 800 Independence Avenue, SW., Washington. D.C. 20591.

FOR FURTHER INFORMATION CONTACT: Mr. Everett L. McKisson, Airspace Regulations Branch (AAT-230), Airspace and Air Traffic Rules Division, Air Traffic Service, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, D.C., 20591; telephone: (202) 426-3715.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested persons may participate in the proposed rulemaking by submitting such written data, views or arguments as they may desire. Communications should identify the airspace docket number and be submitted in triplicate to the Director, Southern Region, Attention: Chief, Air Traffic Division, Federal Aviation Administration, P.O. Box 20636, Atlanta, Ga., 30320. All communications received on or before August 22, 1979, will be considered before action is taken on the proposed amendment. The proposal contained in this notice may be changed in the light of comments received. All comments submitted will be available, both before and after the closing date for comments, in the Rules Docket for examination by interested persons.

Availability of NPRM

Any person may obtain a copy of this Notice of Proposed Rule Making (NPRM) by submitting a request to the Federal Aviation Administration, Office of Public Affairs, Attention: Public Information Center, APA-430, 800 Independence Avenue, SW., Washington, D.C., 20591, or by calling (202) 426-8058. Communications must identify the docket number of this NPRM. Persons interested in being placed on a mailing list for future NPRMs should also request a copy of Advisory Circular No. 11-2 which describes the application procedures.

The Proposal

The FAA is considering an amendment to Part 73 of the Federal Aviation Regulations that would enlarge subareas G, H, and J of R-5314.

The additional area is required to contain the turning and run in tracks of high performance military aircraft operation at subsonic speeds in excess of 250 knots. The U.S. Air Force is the lead agency for the purposes of compliance with the National Environmental Policy Act. Headquarters Tactical Air Command/DEEV, Langley AFB, VA., 23365, Attention: Capt. William Gantt, telephone: (804) 764-4430, is the agency to which comments on the environmental and land use aspects can be addressed. The designated altitude, time of designation, controlling agency, and using agency remain unchanged for all of the Dare County, N.C., restricted areas.

The Proposed Amendment

Accordingly, pursuant to the authority delegated to me, the Federal Aviation Administration proposes to amend § 73.53 of Part 73 of the Federal Aviation Regulations (14 CFR Part 73) as republished (44 FR 705) as follows:

Under R-5314, Subarea G, all before "Designated altitudes." is deleted and "Boundaries. Beginning at Lat. 35°51'35"N., Long. 75°57'55"W; to Lat. 35°38'55"N., Long. 76°01'00"W; to Lat. 35°39'20"N., Long. 76°05'00"W; to Lat. 35°51'59"N., Long. 76°02'08"W; to the point of beginning." is substituted therefor.

Under R-5314, Subarea H, all before "Designated altitudes." is deleted and "Boundaries. Beginning at Lat. 35°51'59"N., Long. 76°02'08"W; to Lat. 35°39'20"N., Long. 76°05'00"W; to Lat. 35°40'25"N., Long. 76°12'25"W; to Lat. 35°52'42"N., Long. 76°09'49"W; to the point of beginning." is substituted therefor.

Under R-5314, Subarea J, and all before "Designated altitudes." is deleted and "Boundaries. Beginning at Lat. 35°52'42"N., Long. 76°09'49"W; to Lat. 35°43'25"N., Long. 76°12'25"W; to Lat. 35°43'50"N., Long. 76°35'30"W; to Lat. 35°54'50"N., Long. 76°33'10"W; to the point of beginning." is substituted therefor.

(Secs. 307(a), 313(a), Federal Aviation Act of 1958 (49 U.S.C. 1348(a) and 1354(a)); sec. 6(c), Department of Transportation Act (49 U.S.C. 1655(c)); and 14 CFR 11.65))

Note.—The FAA has determined that this document involves a proposed regulation which is not significant under Executive Order 12044, as implemented by DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979). Since this regulatory action involves an established body of technical requirements for which frequent and routine amendments are necessary to keep them operationally current and promote safe flight operations, the anticipated impact is so minimal that this action does not warrant preparation of a regulatory evaluation and a comment period of less that 45 days is appropriate.

Issued in Washington, D.C. on July 16, 1979.

B. Keith Potts,

Acting Chief, Airspace and Air Traffic Rules Division.

[FR Doc. 79-22675 Filed 7-20-79; 8:45 am]

BILLING CODE 4910-13-M

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

Office of the Secretary

[24 CFR Part 570]

[Docket No. R-79-685]

Community Development Block Grants, Content of Housing Assistance

AGENCY: Department of Housing and Urban Development.

ACTION: Notice of Transmittal of interim rule to Congress under Section 7(o) of the Department of HUD Act.

SUMMARY: Recently enacted legislation authorizes Congress to review certain HUD rules for fifteen (15) calendar days of continuous session of Congress prior to each such rule's publication in the Federal Register. This Notice lists and summarizes for public information an interim rule which the Secretary is submitting to Congress for such review.

FOR FURTHER INFORMATION CONTACT: Burton Bloomberg, Director, Office of Regulations, Office of General Counsel, 451 7th Street, S.W., Washington, D.C. 20410 (202) 755-6207.

SUPPLEMENTARY INFORMATION: Concurrently with issuance of this Notice, the Secretary is forwarding to the Chairmen and Ranking Minority Members of both the Senate Banking, Housing and Urban Affairs Committee and the House Banking, Finance and Urban Affairs Committee the following rulemaking document:

PART 570—COMMUNITY DEVELOPMENT BLOCK GRANTS—CONTENT OF HOUSING ASSISTANCE PLAN

This interim rule would revise the rules to be followed by applicants for entitlement grants and small cities grants with respect to inclusion in the Housing Assistance Plan of an assessement of the needs of lower-income households who could reasonably be expected to reside in an applicant's jurisdiction. This revision would conform HUD's rules to the changes in requirements made by the Housing and Community Development Amendments of 1978.

(Sec. 7(o), Department of HUD Act, (42 U.S.C. 3535(o)), sec. 324, Housing and Community Development Amendments of 1978)

Issued at Washington, D.C., July 16, 1979.

Patricia Roberts Harris,

Secretary, Department of Housing and Urban Development.

[FR Doc. 79-22696 Filed 7-20-79; 8:45 am]

BILLING CODE 4210-01-M

[24 CFR Part 42]

[Docket No. R-79-686]

Uniform Relocation Assistance and Real Property Acquisition (Relocation of Mobile Home Occupants Displaced by a HUD-Assisted Project)

AGENCY: Department of Housing and Urban Development.

ACTION: Notice of Transmittal of proposed rule to Congress under Section 7(o) of the Department of HUD Act.

SUMMARY: Recently enacted legislation authorizes Congress to review certain HUD rules for fifteen (15) calendar days of continuous session of Congress prior to each such rule's publication in the Federal Register. This Notice lists and summarizes for public information an interim rule which the Secretary is submitting to Congress for such review.

FOR FURTHER INFORMATION CONTACT: Burton Bloomberg, Director, Office of Regulations, Office of General Counsel, 451 7th Street, S.W., Washington, D.C. 20410 (202) 755-6207.

SUPPLEMENTARY INFORMATION: Concurrently with issuance of this Notice, the Secretary is forwarding to the Chairmen and Ranking Minority Members of both the Senate Banking, Housing, and Urban Affairs Committee and the House Banking, Finance and Urban Affairs Committee the following rulemaking document:

24 CFR PART 42—UNIFORM RELOCATION ASSISTANCE AND REAL PROPERTY ACQUISITION (RELOCATION OF MOBILE HOME OCCUPANTS DISPLACED BY A HUD-ASSISTED PROJECT)

This interim rule would revise 24 CFR Part 42 by adding a new Subpart H stating HUD's relocation assistance policies in connection with mobile homes. This new subpart would provide guidelines for determining eligibility for relocation assistance, under the Uniform Relocation Act, of persons displaced from mobile homes by HUD-assisted project.

(Sec. 7(o), Department of HUD Act, 42 U.S.C. 3535(o), sec. 324, Housing and Community Development Amendments of 1978)

Issued at Washington, D.C. July 17, 1979.

Patricia Roberts Harris,

Secretary, Department of Housing and Urban Development.

[FR Doc. 79-22610 Filed 7-20-79; 8:45 am]

BILLING CODE 4210-01-M

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Public Health Service

Center for Disease Control

[42 CFR Part 71]

Foreign Quarantine: Importation of Certain Things; Dogs and Cats

AGENCY: Center for Disease Control, PHS, HEW.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The proposed revision will modify requirements for importation of dogs and cats into the United States by (1) eliminating the inspection requirements for wild dogs and wild cats, and vaccination requirements for wild dogs; (2) prescribing currently available vaccines; and (3) allowing domestic dogs requiring rabies vaccination to be vaccinated at their destination rather than at the port of entry.

The changes are proposed because wild dogs and wild cats have not been a source of rabies or other communicable disease; therefore, inspection and vaccination are neither necessary nor practical. Also, vaccines listed in the existing regulation are no longer available. The current procedure requiring dogs to be vaccinated at the port of entry is being changed to eliminate undue hardship to the owners, inspectional staff, and carrier representatives, and to reduce the expense to the owners of having domestic dogs vaccinated at the port of entry. The proposed changes will allow wild dogs and wild cats to be admitted without restrictions, prescribe currently available rabies vaccines, and facilitate the admission of dogs requiring vaccination.

DATES: Written comments must be received on or before September 4, 1979. proposed effective date: Upon publication of the final rule in the Federal Register.

ADDRESSES: Comments or inquiries may be submitted in writing to the Director, Quarantine Division, Bureau of Epidemiology, Center for Disease Control, Atlanta, Georgia 30333. All relevant material received within the comment period will be considered. Comments will be available for public inspection at the Center for Disease Control, 1600 Clifton Road, NE., in Room 4067, Atlanta, Georgia, between 8 a.m. and 4:30 p.m., Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Mr. Joseph F. Giordano, Director, Quarantine Division, Bureau of Epidemiology, Center for Disease Control, PHS, HEW, Atlanta, Ga. 30333, telephone 404-329-3674, or FTS: 236-3674.

SUPPLEMENTARY INFORMATION: The current regulation is intended to prevent the introduction of communicable disease, especially rabies, with the importation of domestic or wild dogs or domestic or wild cats. Importation of wild dogs or wild cats is not known to constitute a significant communicable disease hazard. No rabies vaccines are available for immunization of wild dogs. Rabies vaccines available for immunization of domestic dogs have changed since the present regulation was implemented. These changes make the present regulation outdated.

The present regulation requires, in some instances, that an imported dog be detained and confined at the port of entry pending the arrival of a veterinarian to vaccinate the animal. The proposed regulation will allow the dog, under similar circumstances, to proceed to destination in confinement without delay and for vaccination to be performed at destination. This will expedite disposition of imported dogs, effect a monetary savings for the owner, and reduce inspectional staff time.

The Executive Committee of the National Association of State Public Health Veterinarians has urged that this regulation be updated to reflect changes mentioned above. The group has reviewed the proposed revision and has concurred in the proposed changes.

It is therefore proposed to revise § 71.154 in Part 71 of Title 42, Code of Federal Regulations, as set forth below.

Dated: April 24, 1979.

Charles Miller,

Acting Assistant Secretary for Health.

Approved: May 24, 1979.

Joseph A. Califano, Jr.,

Secretary.

§ 71.154 Importation requirements for dogs and cats.

(a) *Definitions.* As used in this section and § 71.155 which deals with disposition of excluded dogs and cats, the term:

"Cat" includes all domestic cats.

"Confinement" means restriction of a dog or cat to a building or other enclosure at the port of entry, en route to destination, and at destination, in isolation from other animals and from persons except for contact necessary for its care or, if the dog or cat is allowed out of the enclosure, muzzling and keeping it on a leash.

"Director" means the Director, Center for Disease Control, Public Health Service, U.S. Department of Health, Education, and Welfare, or the person to whom the authority involved has been delelgated.

"Dog" includes all domestic dogs.

"Owner" means owner or agent.

"Quarantine officer" means quarantine officer or the person to whom the authority involved has been delegated.

"United States" means the States, the District of Columbia, Puerto Rico, and the Virgin Islands.

"Valid rabies vaccination certificate" means a certificate which was issued for a dog not less than 3 months of age at the time of vaccination and which—

(i) Identifies a dog on the basis of breed, sex, age, color, markings, or other information.

(ii) Specifies a date of rabies vaccination at least 30 days before the date of arrival of the dog.

(iii) Specifies a date of expiration which is after the date of arrival of the dog. If no date of expiration is specified, then the date of vaccination shall be no more than 12 months before the date of arrival.

(iv) Bears the signature of a licensed veterinarian.

(b) *General requirements for admission of dogs and cats.*—(1) *Inspection by quarantine officer.* The quarantine officer shall inspect all dogs and cats which arrive at a port of entry from a foreign area. The quarantine officer shall admit only those dogs and cats which show no signs of communicable disease as defined in § 71.1(b).

(2) *Examination by veterinarian and confinement of dogs and cats.* When a dog or cat does not appear to be in good health on arrival (i.e., it has symptoms such as emaciation, lesions of the skin, nervous system disturbances, jaundice, or diarrhea), the officer in charge may require prompt confinement and give the owner an opportunity to arrange for a licensed veterinarian to examine the animal and give or arrange for any tests or treatment indicated. The officer in charge will consider the findings of the examination and tests in determining whether or not the dog or cat may have a communicable disease. The owner shall bear the expense of the examination, tests, and treatment. When it is necessary to detain a dog or cat pending determination of its admissibility, the owner shall provide confinement facilities which in the judgment of the officer in charge will afford protection against any communicable disease. The owner shall bear the expense of confinement. Confinement shall be subject to conditions specified by the officer in charge to protect the public health.

(3) *Record of sickness or death of dogs and cats and requirements for exposed animals.* (i) The person responsible for the care of dogs and cats shall maintain a record of sickness or death of animals en route to the United States and shall submit the record to the quarantine officer at the port of entry. Dogs or cats which have become sick while en route or are dead on arrival shall be separated from other animals as soon as the sickness or death is discovered, and shall be held in confinement pending any necessary examination as determined by the officer in charge.

(ii) When a dog or cat appears healthy but, during shipment, has been exposed to a sick or dead animal suspected of having a communicable disease, the exposed dog or cat shall be admitted only if examination or tests made on arrival reveal no evidence that the animal may be infected with a communicable disease. The provisions of subparagraph (2) of this paragraph shall be applicable to the examination or tests.

(4) *Sanitation.* When the quarantine officer finds that the cages or other containers of dogs or cats arriving in the United States are in an unsanitary or other condition that may constitute a communicable disease hazard:

(i) The dogs or cats shall not be admitted in such containers unless the owner has the containers cleaned and disinfected; and

(ii) The quarantine officer shall report the matter to the U.S. Customs Service Officer for investigation pursuant to U.S. Customs regulations (19 CFR 12.26(k)) regarding importation of animals under inhumane or unhealthful conditions.

(c) *Rabies vaccination requirements for dogs.* (1) The quarantine officer shall require submittal of a valid rabies vaccination certificate at the port of entry for admission of a dog into the United States unless the owner submits evidence satisfactory to the quarantine officer that:

(i) If a dog is less than 6 months of age, it has been only in a country determined by the Director to be rabies-free;[1] or (ii) If a dog is 6 months of age or older, for the 6 months before arrival, it has been only in a country determined by the Director to be rabies-free;[1] or

(iii) The dog is to be taken to research facility to be used for research purposes and vaccination would interfere with its use for such purposes.

(2) Notwithstanding the provisions of paragraph (c)(1) of this section, the quarantine officer may authorize admission as follows:

(i) If the date of vaccination shown on the vaccination certificate is less than 30 days before the date of arrival, the dog may be admitted, but it must be confined until at least 30 days have elapsed since the date of vaccination.

(ii) If the dog is less than 3 months of age, it may be admitted, but it must be confined until it is vaccinated against rabies at 3 months of age. Also, it must be kept in confinement for at least 30 days after the date of vaccination.

(iii) If the dog is 3 months of age or older, it may be admitted, but it must be confined until it is vaccinated against rabies. The dog must be vaccinated within 4 days after arrival at destination but no more than 10 days after arrival at port of entry. Also, it must be kept in confinement for at least 30 days after the date of vaccination.

(3) When a dog is admitted under subparagraph (2) of this paragraph, the quarantine officer shall notify the health department or other appropriate agency having jurisdiction at the point of destination and shall provide the health department with the address of the specified place of confinement and other pertinent information to facilitate surveillance and other appropriate action.

(d) *Certification requirements.* The owner shall submit such certification regarding confinement and vaccination prescribed under this section as may be required by the Director.

(e) *Additional requirements for the importation of dogs and cats.* Dogs and cats coming from areas having a high rate of rabies shall be subject to additional requirements or exclusion as may be determined by the Director to be necessary to protect the public health.

(f) *Requirements for dogs and cats in transit.* The provisions of this section shall apply to dogs and cats transported through the United States from one foreign country to another, except as provided below:

(1) Dogs and cats that appear healthy, but have been exposed to a sick or dead

[1] A current list of rabies-free countries may be obtained from the Director, Quarantine Division, Bureau of Epidemiology, Center for Disease Control, Atlanta, Georgia 30333.

animal suspected of having a communicable disease, need not undergo examination or tests as provided in paragraph (b)(3) of this section if the quarantine officer determines that the conditions under which they are being transported will afford adequate protection against introduction of communicable disease.

(2) Rabies vaccination is not required for dogs that are transported by aircraft or vessel and retained in custody of the carrier under conditions preventing introduction of rabies.

[FR Doc. 79-22867 Filed 7-20-79; 8:45 am]

BILLING CODE 4110-86-M

FEDERAL EMERGENCY MANAGEMENT AGENCY

[44 CFR Part 67]

[Docket No. FI-5665]

National Flood Insurance Program; Proposed Flood Elevation Determinations[1]

AGENCY: Office of Federal Insurance and Hazard Mitigation, FEMA.

ACTION: Proposed rule.

SUMMARY: Technical information or comments are solicited on the proposed base (100-year) flood elevations listed below for selected locations in the nation. These base (100-year) flood elevations are the basis for the flood plain management measures that the community is required to either adopt or show evidence of being already in effect in order to qualify or remain qualified for participation in the National Flood Insurance Program (NFIP).

DATES: The period for comment will be ninety (90) days following the second publication of this proposed rule in a newspaper of local circulation in each community.

ADDRESSES: See table below.

FOR FURTHER INFORMATION CONTACT: Mr. Richard W. Krimm, National Flood Insurance Program, (202) 755-5581 or Toll Free Line (800) 424-8872 (In Alaska and Hawaii call Toll Free Line (800) 424-9080), Room 5270, 451 Seventh Street, S.W., Washington, D.C. 20410.

SUPPLEMENTARY INFORMATION: The Federal Insurance Administrator gives notice of the proposed determinations of base (100-year) flood elevations for selected locations in the nation, in accordance with section 110 of the Flood Disaster Protection Act of 1973 (Pub. L. 93-234), 87 Stat. 980, which added section 1363 to the National Flood Insurance Act of 1968 (Title XIII of the Housing and Urban Development Act of 1968 (Pub. L. 90-448), 42 U.S.C. 4001-4128, and 44 CFR Part 67.4(a).)

These elevations, together with the flood plain management measures required by section 60.3 of the program regulations, are the minimum that are required. They should not be construed to mean the community must change any existing ordinances that are more stringent in their flood plain management requirements. The community may at any time enact stricter requirements on its own, or pursuant to policies established by other Federal, State or Regional entities. These proposed elevations will also be used to calculate the appropriate flood insurance premium rates for new buildings and their contents and for the second layer of insurance on existing buildings and their contents.

The proposed base (100-year) flood elevations for selected locations are:

[1]This new format for Federal Register publication of the Federal Emergency Management Agency's base flood elevation determinations for communities under the National Flood Insurance Program is being introduced to enhance readability and conserve space. Previous determinations were published as separate documents for each community.

Proposed Base (100-Year) Flood Elevations

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Colorado	Eaton (Town), Weld County	Eaton Draw	Downstream Corporate Limits—100 feet upstream from crossing	*4,789
			County Road 74-150 feet downstream from centerline	*4,802
			County Road 74—at centerline	*4,808
Maps available at Town Hall, 2231 First Street, Eaton, Colorado.				
Send comments to: Mr. Gary Carsten, Town Manager, Town of Eaton, Town Hall, 2231 First Street, Eaton, Colorado 80615.				
Connecticut	City of Groton, New London County.	Long Island Sound	Coastline	*11
			Thames River	*11
			Birch Plain Creek	*11
Maps available at the Office of the Building and Zoning Officials, Municipal Building.				
Send comments to: Honorable David B. Sweet, Mayor of Groton, Municipal Building, 295 Meridian Street, Groton, Connecticut 06340.				
Illinois	Fox River Grove, McHenry County.	Fox River	Western corporate limit	*736
			Eastern corporate limit	*737
Maps available at Village President's Office, Fox River Grove, Illinois.				
Send comments to Mr. James Wittig, Village President, Village of Fox River Grove, 408 Northwest Highway, Fox River Grove, Illinois 60021.				
Illinois	New Lenox, Will County	Hickory Creek	Western corporate limit	*619
			200 feet upstream from Vine Street	*622
			200 feet upstream of Cedar Road	*628
			Eastern corporate limit	*630
Maps available at Village Hall, 201 North Church Street, New Lenox, Illinois.				
Send comments to: Mr. Joseph E. Hortung Village President, Village of New Lenox, Village Hall, 201 North Church Street, New Lenox, Illinois 60451.				

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	Winnebago County	Rock River	County Boundary (Downstream)	*691
			Confluence of Kishwaukee River	*695
			Belt Line Road	*697
			Upstream of U.S. Highway 20	*699
			7,250' upstream of U.S. Highway 20 (At corporate limits)	*701
			Confluence of Mud Creek	*713
			Upstream of Latham-Ralston Road	*718
			Downstream of Roscoe Road	*720
			Confluence of Dry Creek	*723
			Downstream of Illinois Highway 2	*725
			Upstream of Rockton Road	*727
			Rockton Dam	*729
			Upstream of Prairie Hill Road	*732
			Corporate Limits (7,000 feet above Prairie Hill Road)	*736
		Killbuck Creek	Confluence with Kishwaukee River	*695
			South Bend Road	*698
			Upstream of Old South Bend Road	*702
			Upstream of U.S. Highway 51	*711
			1,750' downstream of County Boundary	*717
		Kishwaukee River	Upstream of Kishwaukee Road	*695
			Downstream of Belt Line Road	*700
			Upstream of U.S. Highway 51	*705
			Downstream Black Hawk Road	*716
			Upstream of Illinois Central Gulf Railroad	*722
			Downstream of Interstate 90	*729
		South Branch Kishwaukee River	Confluence with Kishwaukee River	*718
			Upstream of Blomburg Road	*724
			Edson Road	*734
		Madigan Creek	Confluence with Kishwaukee River	*725
			Upstream of Mill Road	*728
			Upstream of Chicago and North Western Railway	*737
			Upstream of U.S. Highway 20	*745
			Upstream of of Old Harrison Avenue	*758
			Upstream of Harrison Avenue	*768
			Upstream of Charles Street	*767
			1,750' upstream of Charles Street	*778
		Keith Creek	Country Club Road	*790
			Upstream of Guliford Road	*808
			Downstream of Wild Ginger Road	*819
			Coachman Court	*824
			Downstream of Mulford Road	*836
			Downstream of Vehicle Ford	*853
			Upstream of Shaw Road	*856
			McFarland Road (Extended)	*864
		Spring Creek	Downstream of Brookview Road	*766
			Upstream of Alpine Road	*783
			Upstream of Spring Creek road	*787
			Upstream of Private Drive	*809
		Main Drainage Ditch	Upstream of Private Factory Road	*731
			Private Railroad	*734
			Confluence of Ditch No. 3	*744
			Upstream of Forest Hills Road	*752
			Upstream of Alpine Road	*755
			Corporate Limits (Upstream)	*761
		Ditch No. 3	Confluence with Main Drainage Ditch	*744
			Upstream of Windsor Road	*746
			Upstream of Alpine Road	*748
			Forest Hills Road	*764
			Corporate Limits above Forest Hill Road	*768
		Willow Creek	Confluence with Rock River	*715
			Upstream of U.S. Highway 51	*725
			Upstream of Alpine Road	*741
			Downstream Corporate Boundary with City of Loves Park	*756
			Upstream Corporate Boundary with City of Loves Park	*762
			Downstream boundary of Rock Cut State Park	*769
		McDonald Creek	Confluence with Rock River	*718
			Downstream of Frontage Road	*728
			Upstream of U.S. Highway 51	*730
			Upstream of Swanson Road	*750
			Upstream of McDonald Road	*763
		South Kinnikinnick Creek	Downstream Corporate Limits with Village of Rosco	*735
			Upstream of Chicago and North Western Railway	*741
			Upstream of Interstate 90	*755
			Upstream of Hamborg Road	*760
			Upstream of Atwood Avenue	*781
			Upstream of Private Drive	*791
			Upstream of Burr Oak Road	*801
		North Kinnikinnick Creek	Downstream Corporate Limits with Village of Roscoe	*738
			Upstream of Willow Brook Road	*741
			Upstream of Interstate 90	*759
			Love Road	*768
			South Gate Road (Extended)	*778
			White School Road (Extended)	*799
			3,000' downstream of County Boundary (Upstream)	*811
			County Boundary (Upstream)	*827
		Dry Creek	Confluence with Rock River	*723
			Upstream of Forest Preserve Road	*728
			Upstream of Hononegah Road	*732

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Downstream Corporate Limits with Village of Roscoe	*742
			Upstream Corporate Limits with Village of Roscoe	*749
			Upstream of Chicago and North Western Railway	*752
			Upstream of Rockton Road	*758
			Upstream of Willow Brook Road	*768
			Downstream of Northwest Tollway	*771
			Downstream of Manchester Road	*773
			Upstream of Middle Road	*780
			5,500' upstream of Middle Road	*787
		South Branch Dry Creek	Confluence with Dry Creek	*758
			Downstream of Willow Brook Road	*762
			Upstream of Northwest Tollway	*768
			Love Road	*774
			3,000' downstream of White School Road	*810
			Downstream of White School Road	*834
			Farm Bridge	*843
			Upstream of Rockton Road	*856
			2,000' downstream of County Line Road	*883
			Downstream of County Line Road	*903
		Turtle Creek	Confluence with Rock River	*737
			State Boundary	*750
		North Kent Creek	Corporate Limits downstream of Johnson Avenue	*724
			Johnson Avenue	*725
			Saford Road	*733
			Confluence of Kilburn Creek	*739
			Downstream of Page Park Dam	*753
			Upstream of Page Park Dam	*765
			Upstream of Meridian Road	*766
			Upstream of Harrison Road	*770
			Downstream of Wempleton Road	*783
			Upstream of Auburn Road	*795
			3,300' upstream of Auburn Road	*799
		Kilburn Creek	Confluence with North Kent Creek	*739
			State Route 70	*750
			Downstream of Lakewood Hills Dam	*752
			Upstream of Lakewood Hills Dam	*757
			Upstream of Lakeside Drive	*760
			3,400' upstream of Lakeside Drive	*776
		South Kent Creek	Upstream of Horace Avenue	*729
			Upstream of Cunningham Road (Downstream Crossing)	*731
			Downstream of Illinois Central Gulf Railroad (Downstream Crossing)	*733
			Upstream of Illinois Central Gulf Railroad (Upstream Crossing)	*745
			Upstream of U.S. Highway 20	*746
			Upstream of Centerville Road	*749
			Upstream of Private Drive	*751
			Downstream of Cunningham Road (Crossing between Meridian Road and Centerville Road).	*754
			Upstream of Cunningham Road (Crossing between Meridian Road and Centerville Road).	*763
			Upstream of Meridian Road	*767
			Weldon Road	*803
			Cunningham Road (Upstream Crossing)	*803
		Mud Creek	Confluence with Rock River	*713
			Upstream of Private Road	*736
			1,000' upstream of Rockton Avenue	*751
		Pecatonica River	Confluence with Rock River	*727
			Upstream of Meridian Road	*728
			Upstream of State Route 75	*731
			Upstream of State Route 70	*736
			Upstream of Pecatonica Road	*744
		Sugar River	Confluence with Pecatonica River	*729
			Downstream of Chicago, Milwaukee, St. Paul and Pacific Railroad	*735
			Upstream of Winslow Road	*740
			Yale Bridge Road	*741
			State Boundary (Upstream)	*743
		Otter Creek	Confluence with Sugar River	*740
			Downstream of Wheeler Road	*745
			Confluence with North and South Branch Otter Creek	*752
		North Branch Otter Creek	Upstream with Otter Creek	*752
			Upstream of Crowley Road	*759
			Upstream of Patterson Road	*767
			Upstream of Field Road	*783
			Upstream of Rock Grove Road	*786
			Yale Brook Road	*791
			Upstream of Best Road	*795
			700' downstream of North Hartman Road	*809
		South Branch Otter Creek	Confluence with Otter Creek	*752
			Downstream of Fritz Road	*758
			Downstream of Center Road	*765
			Upstream of Patterson Road	*769
			Upstream of Chicago, Milwaukee, St. Paul and Pacific Railroad	*774
			Upstream of Pecatonica Road	*777
			Upstream of Durand Road	*782
		Randalls Creek	Confluence with North Branch Otter Creek	*773
			Upstream of Rock Grove Road	*779
			Yale Bridge Road	*791

Maps available at the Courthouse, Winnebago County, Illinois.

Send comments to: Mr. Laurence Ralston, Chairman of the County Board, Winnebago County Courthouse Building, Rockford, Illinois 61101.

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Indiana	Chesterfield, Madison County	Mill Creek	Approximately 25 feet upstream from northern corporate limit	*875
			Approximately 440 feet upstream from northern corporate limit	*882
			Approximately 600 feet downstream from Main Street	*888
			Approximately 150 feet downstream from Main Street	*892
			Located at Main Street	*895
			Just upstream from Main Street	*898
			Approximately 120 feet upstream from Main Street	*901
			Approximately 40 feet upstream from Conrail	*904
			Just upstream from State Road 67	*906
			Just downstream from Mulberry Road	*907
			Just downstream from southern corporate limit	*907
		White River	Approximately 2,860 feet downstream from Water Street	*868
			Approximately 3,500 feet upstream from Water Street	*869

Maps available at Town Hall, 207 East Main Street, Chesterfield, Indiana.

Send comments to Mr. Rick Grills, President of the Town Board, Town of Chesterfield, Town Hall, 207 East Main Street, Chesterfield, Indiana 46017

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
	Schererville, Lake County	Schererville Ditch	At confluence with Dyer Ditch	*628
			Just upstream of 68th Avenue	*629
			Just upstream of Roman Drive	*631
		Schilling Ditch	At confluence with Dyer Ditch	*632
			About 500 feet downstream of U.S. Route 30	*632
			About 500 feet upstream of U.S. Route 30	*637
			About 0.7 mile upstream of Sunset Boulevard	*638
			At southern corporate limits, about 1.3 miles upstream of Sunset Boulevard.	*651
		Seberger Ditch	Just upstream of Main Street	*621
			Just downstream of Conrail	*625
			Just upstream of Conrail	*628
			Just downstream of Central Avenue	*630
			Just upstream of Central Avenue	*632
			About 300 feet upstream of Redar Drive	*634
		Turkey Creek	At eastern corporate limit	*632
			Just upstream of gravel road, about 500 feet downstream of Cline Avenue.	*635
			Just upstream of Joliet Street	*636
			Just downstream of U.S. Route 30	*647
			Just upstream of U.S. Route 30	*650
			About 900 feet upstream of Conrail	*651
		Dyer Ditch	Just upstream of Airport Road	*626
			Just downstream of Conrail	*627
			Just upstream of Elgin Joliet & Eastern Railway	*628
			About 0.4 mile upstream of Elgin Joliet & Eastern Railway	*629
			Just upstream of U.S. Route 30	*635
			About 0.4 mile upstream of U.S. Route 30	*638

Maps available at Town Hall, 1640 Wilson Street, Schererville, Indiana.

Send comments to Mr. Richard Krame, Town Board President, Town of Schererville, Town Hall, 1640 Wilson Street, Schererville, Indiana 46375.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Iowa	Lake View, Sac County	Blackhawk Lake	Entire shoreline	*1,224
		Provost Slough	Entire shoreline	*1,224
		Arrowhead Lake	Entire shoreline	*1,224

Maps available at City Hall, City Clerk's Office, 305 Main Street, Lake View, Iowa.

Send comments to: The Honorable Lawrence Bruner, Mayor, City of Lake View, City Hall, 305 Main Street, Lake View, Iowa 51450.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Maine	Chelsea, Kennebec County	Kennebec River	At Chelsea-Randolph Townline	*30
			Just downstream of Farmingdale Townline	*31
			At mouth of Vaughn Brook	*31
			Approximately 4,600 feet upstream of mouth of Vaughn Brook	*32
		Togus Stream	At Chelsea-Pittson Townline	*80
			Approximately 300 feet upstream Chelsea-Pittson Townline	*84
			Approximately 2,500 feet upstream Chelsea-Pittson Townline	*87
			Approximately 3,050 feet upstream Chelsea-Pittson Townline	*96
			Approximately 6,000 feet upstream Chelsea-Pittson Townline	*102
			Approximately 6,900 feet upstream Chelsea-Pittson Townline	*108
			Approximately 250 feet upstream Searles Mill Road	*110
			Approximately 1,000 feet upstream Searles Mill Road	*115
			Just upstream of Windsor Road	*131
			Approximately 1,300 feet downstream of confluence of Chase Meadow Brook.	*133
			Approximately 750 feet downstream of confluence of Chase Meadow Brook.	*137
			Just upstream confluence of Chase Meadow Brook	*141
			Approximately 175 feet downstream of Gravel Pit Road	*144
			Approximately 300 feet upstream of Gravel Pit Road	*150
			Approximately 500 feet upstream of Gravel Pit Road	*155
			Approximately 100 feet downstream of Wellman Road	*158
			Approximately 500 feet upstream of Wellman Road	*165
			Just downstream of Route 17 By-pass	*168
			Just upstream of Route 17 By-pass	*169
			Just downstream of Route 17	*175
			Just upstream of Route 17	*178

Maps available at Town Office, Town of Chelsea, Chelsea, Maine 04345.

Send comments to: Mr. Howard Crowell, Town Manager, Town of Chelsea, Town Office, Chelsea, Maine 04345.

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Maine	Phillips, Franklin County	Sandy River	At the southern corporate limit	*538
			Just downstream of Bridge Street	*550
			Approximately 400 feet upstream of Bridge Street	*560
			Just upstream of Park Street	*603

Maps available at Town Office, Main Street, Phillips, Maine.

Send comments to: Laura W. Tooehaker, Town Manager, Town of Phillips, Town Office, Main Street, Phillips, Maine 04966.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Maine	Town of Pittston, Kennebec County.	Kennebec River	Downstream Corporate Limits	*25
			Confluence of Morton Brook	*26
			Upstream Corporate Limits	*28
		Togus Stream	Confluence with Kennebec River	*28
			State Route 27 Bridge	*28
			Confluence of Tony Meadow Brook	*68
			Barber Road Bridge (Upstream)	*74
			Upstream Corporate Limit	*81

Maps available at the Fire Station and the regional Planning Office, 125 State Street, Augusta, Maine.

Send comments to: Mr. Clifton Moody, First Selectman of Pittston, Town Office, Route 4, Gardiner, Maine 04345.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Massachusetts	Town of Danvers, Essex County	Ipswich River	West Street Upstream Side	*48
			Andover Street (State Route 114) Upstream Side	*49
		Porter River	State Route 128	*11
		Frost Fish Brook	Massachusetts Avenue Upstream Side	*14
			Coolidge Road Downstream Side	*17
		Crane River	Water Street (State Route 35)	*11
			State Route 128	*11
		Crane Brook	Downstream crossing of Cemetery Road Upstream Side	*15
			Sylvan Street Dam and Bridge, Upstream Side	*25
			Collins Street Upstream Side	*28
			Andover Street (State Route 114) Upstream Side	*30
			Boston and Maine Railroad, Upstream Side, located 0.3 mile upstream Andover Street.	*41
		Beaver Brook	Holten Street Upstream Side	*32
			Hobart Street	*33
			Beaver Park Road Upstream Side	*36
			Maple Street Downstream Side	*45
			Maple Street Upstream Side	*52
			Nicholas Street Downstream Side	*57

Maps available at the Office of the Town Clerk and the Danvers Public Library.

Send comments to: Mr. Kenneth G. Bellevue, Chairman of the Board of Selectmen of Danvers, Town Hall, Danvers, Massachusetts 01923.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Massachusetts	Reading Middlesex County	Ipswich River	Downstream corporate limit	*70
			Just downstream Mill Street	*71
			Upstream corporate limit	*76
		Bear Meadow Brook	About 500 feet downstream of Haverhill Street	*71
			About one mile upstream of Haverhill Street	*76
		Aberjona River	Downstream corporate limit	*67
			Just downstream of West Street culvert	*82
			Divergence with North Spur Aberjona River	*85
		North Spur, Aberjona River	Downstream corporate limit	*75
			Just upstream of West Street	*81
			Just upstream of Willow Street	*85
		Walkers Brook	Downstream corporate limit	*79
			Just downstream of Harvest Road	*84
			Just downstream of Ash Street	*87

Maps available at Town Hall, Town Clerk's Office, 60 Cowell Street, Reading, Massachusetts.

Send comments to: Mr. James Sullivan, Jr., Chairman of the Board of Selectmen, Town of Reading, Town Hall, 60 Cowell Street, Reading, Massachusetts 01867.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	Birmingham (City), Oakland County.	Main River Rouge	Maple Street—25 feet upstream from centerline	*725
			Hunter Boulevard—100 feet downstream from centerline	*748
			15 Mile Road—at centerline	*750
		Quarton Lake Branch	Quarton Lake Dam—10 feet downstream from centerline	*727
			Quarton Lake Dam—10 feet upstream from centerline	*736
			Redding Street—10 feet upstream from centerline	*748

Maps available at the Office of the City Engineer, City Hall, 151 Martin Street, Birmington, Michigan.

Send comments to: Honorable George Jackson, Mayor, City of Birmingham, City Hall, 151 Martin Street, Birmingham, Michigan 48011

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	Farmington (City) Oakland County	Upper River Rouge	Grand River Avenue—50 feet upstream from centerline	*687
			Powers Avenue—200 feet downstream from centerline	*692
			Powers Avenue—30 feet upstream from centerline	*697
			Farmington Road (abandoned)—25 feet upstream from centerline	*713
		Tambusi Creek	Smithfield Road—at centerline	*755
			Brittany Hill Road—at centerline	*787

Maps available at the Office of the City Clerk, City Hall, 23600 Liberty Street, Farmington, Michigan

Send comments to: Honorable Richard Tupper, Mayor, City of Farmington, City Hall, 23600 Liberty Street, Farmington, Michigan 48024

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Minnesota	Edina, Hennepin County	Minnehaha Creek	Just upstream of Xerxes Avenue	*853
			Downstream corporate limit	*854
			Just upstream France Avenue South	*861
			Just upstream West 54th Street	*867
			Just upstream Woodale Avenue	*878
			Just upstream Browndale Avenue Dam	*889
			Just upstream West 44th Street	*890
			Upstream corporate limit	*892

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
		Nine Mile Creek	Downstream corporate limit	*821
			Just upstream West 77th Street Ramp	*825
			Just upstream West 70 Street	*832
			Just upstream Minneapolis, Northfield & Southern Railroad	*837
			Just upstream Brook Drive	*841
			Just upstream Valley View Drive	*848
			Just upstream County Highway 62	*853
			Just upstream County Highway 158	*862
			Just upstream Dover Drive	*874
			Upstream corporate limit	*875
		Braemer Branch South Fork Nine Mile Creek.	At mouth	*832
			2,800 feet upstream of mouth	
			4,000 feet upstream of mouth	*844
			Just upstream Braemer Road	*846
			900 feet upstream Valley View Road	*850

Maps available at City Hall, City of Edina, Edina, Minnesota.

Send comments to: The Honorable James Van Valkenburg, Mayor, City of Edina, City Hall, 4801 West 50th Street, Edina, Minnesota 55424.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Minnesota	Little Falls, Morrison County	Mississippi River	Southern corporate limit	*1,092
			Just upstream from Burlington Northern	*1,094
			At Minnesota Power & Light	*1,096

Maps available at City Hall—Engineer's Office and City Administrator's office, 100 North East Senexth Avenue, Little Falls, Minnesota.

Send comments to: The Honorable Joseph H. Sauer, Mayor, City of Little Falls, City Hall, 100 North East Senexth Avenue, Little Falls, Minnesota 56345.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Missouri	Freeman, Cass County	Poney Creek	1975 feet downstream of Old Route "0"	*832
			Just downstream of Old Route "0"	*834
			Just upstream of Old Route "0"	*835
			Just downstream of Route "0"	*836
			500 feet upstream of Route "0"	*842
			2,450 feet upstream of Route "0"	*843

Maps available at City Hall, Freeman, Missouri.

Send comments to: The Honorable Clint Kisner, Mayor, City of Freeman, City Hall, Freeman, Missouri 64746.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Montana	Lincoln County Unincorporated Areas.	Big Cherry Creek	Confluence with Libby Creek	*2,144
			U.S. Highway 2 Bridge—90 feet upstream from centerline	*2,198
			County Road—65 feet upstream from centerline	*2,321
		Bobtail Creek	County Road—10 feet upstream from centerline	*2,067
		Callahan Creek	Burlington Northern Railroad—80 feet upstream from centerline	*1,866
			Corporate limits (2nd crossing)	*1,914
		Flower Creek	Sewage Plant Road—65 feet upstream from centerline	*2,057
			Corporate limits (4th crossing)	*2,157
			Sewage Plant Road—230 feet southwest of Flower Creek	#1
		Kootenai River	Confluence with Flower Creek	*2,054
			Private Road—150 feet upstream from centerline	*2,060
		Libby Creek	Burlington Northern Railroad—at centerline	*2,060
			Private Road (2nd crossing)—at centerline	*2,071
			Confluence with Big Cherry Creek	*2,144
			Logging Road to St. Regis Sawmill—115 feet upstream from centerline.	*2,310
			State Highway 482 Bridge—50 feet upstream from centerline	*2,351
		Parmenter Creek	Burlington Northern Railroad—50 feet upstream from centerline	*2,065
			U.S. Highway 2—50 feet upstream from centerline	*2,074
			Dome Mountain Avenue—35 feet upstream from centerline	*2,015
			Highway 2—3,500 feet southwest of intersection with Indian Head Road.	#1
		Quartz Creek	Road Bridge—30 feet upstream from centerline	*2,035
		Tobacco River	Corporate limits (first crossing)	*2,550
			Burlington Northern Railroad—50 feet upstream from centerline	*2,004

Maps available at Lincoln County Courthouse, 418 Mineral Avenue, Libby, Montana.

Send comments to: Mr. Jim Morey, Chairman, Board of County Commissioners, Lincoln County Courthouse, 418 Mineral Avenue, Libby, Montana 59923.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
New Jersey	East Rutherford, Borough Bergen County.	Passaic River	Downstream Corporate Limits	*10
			Upstream Corporate Limits	*10

Maps are available at the Borough Hall, East Rutherford, New Jersey.

Send comments to: Honorable James Plosia, Mayor of East Rutherford, Borough Hall, 111 Patterson Avenue and Everett Place, East Rutherford, New Jersey 07073.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
New York	Sand Lake (Town) Rensselaer County.	Wynants Kill	Stop 13 Road—50 feet downstream from centerline	458*
			Stop 13 Road—50 feet upstream from centerline	483*
			Brookside Park Road—75 feet upstream from centerline	499*
			State Highway 43 (at station 5,550)—150 feet upstream from centerline.	528*
			Thais Road—125 feet upstream from centerline	582*
			Garner Road—150 feet downstream from centerline	607*
			Garner Road—at centerline	614*
			Eastern Union Turnpike—50 feet upstream from centerline	760*
			Glass Lake Road—50 feet downstream from centerline	817*

Maps available at Town Clerks Office, Town Hall, Routes 43 and 66, Sand Lake, NY

Send comments to: Mr. John Udwary, Supervisor, Town of Sand Lake, Town Hall, Sand Lake, NY 12153.

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
North Carolina	Gibsonville (Town), Alamance and Guilford Counties.	Tributary to Travis Creek	Ossipee Street—200 feet upstream from centerline	*612
			Alamance and Guilford County limits	*629
		Back Creek Tributary	U.S. Highway 70—200 feet upstream from upstream face of bridge	*599
			Sanitary Landfill Road—100 feet upstream from centerline	*625
Maps available at Town Hall, 129 West Main Street, Gibsonville, North Carolina.				
Send comments to: Mr. Don Brookshire, Planning Director, Town of Gibsonville, Town Hall, 129 West Main Street, Gibsonville, North Carolina 27249.				
North Carolina	Hillsborough (Town), Orange County.	Eno River	State Route 1197 at centerline	*509
			State Route 1134—150 feet upstream from centerline	*521
			U.S. Highway 70 (upstream crossing)—at centerline	*535
		Cates Creek	U.S. Highway 70 (Business Route)—200 feet upstream from centerline.	*522
			Interstate Highway 85—200 feet downstream from centerline	*551
			Interstate Highway 85—200 feet upstream from centerline	*558
			State Route 1009—10 feet downstream from centerline	*592
Maps available at Town Hall, 101 E. Orange Street, Hillsborough, North Carolina.				
Send comments to: Ms. Rose Guthrie, Town Planner, Town of Hillsborough, Town Hall, 101 E. Orange Street, Hillsborough, North Carolina.				
North Carolina	Salisbury (City), Rowan County	Henderson Branch	Confederate Avenue—40 feet downstream from centerline	*661
			Confederate Avenue—20 feet upstream from centerline	*665
			Annandale Avenue—120 feet downstream from centerline	*666
			Annandale Avenue—40 feet upstream from centerline	*669
			Jackson Street—120 feet downstream from centerline	*687
			Jackson Street—20 feet upstream from centerline	*690
			Church Street—10 feet downstream from centerline	*695
			Church Street—20 feet upstream from centerline	*698
		Henderson Branch Tributary	Henderson Street—at centerline	*695
			Lafayette Street—40 feet downstream from centerline	*708
			Lafayette Street—40 feet upstream from centerline	*709
		Mahaley Branch	Catawba Street—150 feet downstream from centerline	*658
			Catawba Street—50 feet upstream from centerline	*662
			Grove Street—125 feet downstream from centerline	*673
			Grove Street—50 feet upstream from centerline	*682
			Southern Railway—50 feet upstream from centerline	*694
			West Street—75 feet downstream from centerline	*720
			West Street—50 feet upstream from centerline	*724
		Mahaley Branch Tributary	Bank Street—40 feet downstream from centerline	*719
			Bank Street—10 feet upstream from centerline	*721
			West Street—45 feet downstream from centerline	*728
			West Street—10 feet upstream from centerline	*731
		Maple Avenue Branch	Milford Hills Road—100 feet downstream from centerline	*685
			Milford Hills Road—20 feet upstream from centerline	*688
			Earnan Street—80 feet downstream from centerline	*697
			Earnan Street—20 feet upstream from centerline	*700
			Victory Street—50 feet downstream from centerline	*704
			Victory Street—20 feet upstream from centerline	*708
			Wilson Road—50 feet upstream from centerline	*713
		Wiley Avenue Branch	Stanley Street—60 feet downstream from centerline	*698
			Stanley Street—20 feet upstream from centerline	*702
			Jordan Street—60 feet downstream from centerline	*708
			Jordan Street—20 feet upstream from centerline	*709
			Fries Street—100 feet upstream from centerline	*720
			Crosby Street—120 feet downstream from centerline	*735
			Crosby Street—20 feet upstream from centerline	*745
		Park Avenue Branch	Cedar Street—40 feet downstream from centerline	*695
			Cedar Street—140 feet upstream from centerline	*700
		Innis Street Creek	Green Street—100 feet downstream from centerline	*701
			Green Street—200 feet upstream from centerline	*706
			Clay Street—10 feet downstream from centerline	*714
			Clay Street—50 feet upstream from centerline	*719
			Liberty and Shaver Streets—150 feet downstream from centerline	*720
			Liberty and Shaver Streets—50 feet upstream from centerline	*724
		Thomas Street Creek	Boundary Street—10 feet upstream from centerline	*707
			Clay Street—10 feet downstream from centerline	*709
			Clay Street—10 feet upstream from centerline	*712
			Southern Railway—70 feet upstream from centerline	*721
		Main Street Tributary, Hopkins Street Branch.	Military Avenue—at centerline	*730
			Hopkins Street—100 feet downstream from centerline	*710
			Hopkins Street—20 feet upstream from centerline	*714
		Vance Avenue	Hopkins Street—100 feet downstream from centerline	*710
			Hopkins Street—20 feet upstream from centerline	*714
			Carolina and Northwestern Railroad—40 feet downstream from centerline.	*722
			Carolina and Northwestern Railroad—20 feet upstream from centerline.	*738
		Concord Road Creek	Dolly Madison Industries Entrance Road—70 feet downstream from centerline.	*715
			Dolly Madison Industries Entrance Road—20 feet upstream from centerline.	*718
			Service Road—10 feet downstream from centerline	*723
			Service Road—20 feet upstream from centerline	*728
			Interstate 85—10 feet downstream from centerline	*730
			Interstate 85—50 feet upstream from centerline	*731

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
		Tar Branch	Faith Road—100 feet upstream from centerline	*717
			Faith Road—80 feet upstream from centerline	*722
			Rowan Circle—20 feet upstream from centerline	*729
			Rose Avenue—120 feet downstream from centerline	*742
			Rose Avenue—80 feet upstream from centerline	*747
			Carolina Boulevard—40 feet upstream from centerline	*762
		Tar Branch Tributary	Rose Avenue—20 feet upstream from centerline	*745
			Carolina Boulevard—20 feet upstream from centerline	*761
		Town Creek	Bringle Ferry Road—at centerline	*689
			Innis Street—300 feet upstream from centerline	*698
			Vance Avenue—150 feet upstream from centerline	*710
			Klumac Street—at centerline	*716
		Crane Creek	Stokes Ferry Road—100 feet upstream from centerline	*700
			U.S. Highway 52—100 feet downstream from centerline	*701
			Southern Railway—at centerline	*705
		Grants Creek	Old Mocksville Road—20 feet upstream from centerline	*648
			U.S. Highway 601—40 feet upstream from centerline	*655
			U.S. Highway 70—100 feet upstream from centerline	*661
			Southern Railway—100 feet upstream from centerline	*667
			Old Wilkesboro Road—100 feet upstream from centerline	*669
			Annexed area south of Cedar Springs Road—downstream corporate limit.	*691
			Annexed area south of Cedar Springs Road—upstream corporate limit	*693
		Woodleaf Branch	Lincolnton Road—120 feet downstream from centerline	*679

Maps available at City Clerk's Office, 132 North Main, Salisbury, North Carolina.

Send comments to: Mr. Harvey Mathias, Assistant City Manager, City of Salisbury, P.O. Box 479, Salisbury, North Carolina 28144.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Ohio	Avon, Lorain County	French Creek	Downstream corporate limit	*623
			Just upstream Miller Road	*624
			Just upstream Interstate Route 90	*626
			4,190 feet upstream Interstate Route 90	*633
			Just upstream State Route 254	*664
			Just downstream Stony Ridge Road	*671
			Just upstream Stony Ridge Road	*682
			Just downstream State Route 83	*685

Maps available at City Hall, City of Avon, 36774 Detroit Road, Avon, Ohio.

Send comments to: The Honorable Donald Hubbard, Mayor, City of Avon, City Hall, 36774 Detroit Road, Avon, Ohio 44011.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Ohio	Lancaster, Fairfield County	Hocking River	Downstream corporate limit	*807
			Just downstream of Chessie System (near confulence of Tarhe Run)	*816
			Just downstream of Conrail	*819
			Just upstream of Wheeling Street	*822
			About 800 feet downstream of Ety Road	*828
			Upstream corporate limit	*836
		Plesant Run	Downstream corporate limit	*821
			Just downstream of Conrail	*825
			Just downstream of U.S. Route 22	*830
			About 1250 feet downstream of Marietta Road	*837
			Just downstream of Marietta Road	*842
		Baldwin Run	Confluence with Hocking River	*814
			Just upstream of Conrail	*817
			Just uptream of Main Street	*821
	Lancaster, Fairfield County	Ewing Run	Confluence of Fetters Run	*821
			Just downstream Pleasantville Road	*822
			Just downstream of Tiki Lane Road	*868
			About 2200 feet upstream of Tiki Lane Road	*877
			Just downstream of Rainbow Drive	*898
			Just upstream of Rainbow Drive	*903
			Upstream corporate limit	*904
		Fetters Run	Just downstream Cherry Street	*822
			Just downstream Fair Avenue	*830
			About 2900 feet upstream of Fair Avenue	*844
			Just upstream of Granville Pike	*873
			Upstream corporate limit	*877
		Tarhe Run	Just downstream of Columbus Street	*817
			Just upstream of Columbus Street	*821
			Just downstream of Private Road about 400 feet downstream of Broad Street.	*827
			About 100 feet upstream of Broad Street	*838
			About 1300 feet upstream of Broad Street	*842
	Lancaster, Fairfield County	Hunters Run	Confluence with Hocking River	*821
			About 580 feet downstream of Lincoln Avenue	*831
			Just downstream of Lincoln Avenue (at corporate limit)	*834
		Lateral A	Confluence with Hocking River	*823
			Just downstream Memorial Drive	*824
			Just upstream Memorial Drive	*827
			Just downstream of Columbus Road	*853
			About 300 feet upstream of Hawthorne Drive	*863
	Lancaster, Fairfield County	Lateral B	Just downstream of Chessie System	*820
			Just downstream of West Fair Avenue	*831
			Just upstream of West Fair Avenue	*836
			Just downstream of Farm Road	*844
			Just upstream of Farm Road	*849
			About 400 feet upstream of Hoffman Road	*857

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
		Lateral D	Confluence with Hocking River	*831
			Just downstream of Collins Road	*836
			Just downstream of West Fair Avenue	*840
			Upstream corporate limit	*848
Maps available at City Hall, 104 East Main Street, Lancaster, Ohio.				
Send comments to: The Honorable Edward Rutherford, Mayor, Ctity of Lancaster, City Hall, 104 East Main Street, Lancaster, Ohio 43130.				
Ohio	Lockbourne, Hamilton County	Big Walnut Creek	400 feet downstream of Rowe Road	*697
			Just upstream of Rowe Road	*698
			2,500 feet upstream of Rowe Road	*699
Maps available at Village Hall, 85 Commerce Street, Lockbourne, Ohio.				
Send comments to: The Honorable Mr. Cecil Shirkey, Mayor, Village of Lockbourne, Village Hall, 85 Commerce Street, Lockbourne, Ohio 43137.				
Ohio	South Amherst, Lorain County	Squires-Schramm Ditch	At confluence with Beaver Creek	*751
			Just upstream of South Lake Road	*757
			Just upstream of Annis Road	*767
			Upstream corporate limit	*769
Maps available at Village Hall, 103 West Main Street, South Amherst, Ohio.				
Send comments to: The Honorable Kenneth Jones, Mayor, Village of South Amherst, Village Hall, 103 West Main Street, South Amherst, Ohio 44001.				
South Dakota	Box Elder (City), Pennington County.	Box Elder Creek	Spruce Drive—at centerline	*3,020
			Corporate limits—450 feet southwest of intersection of Westside Drive and U.S. Highways 14 and 16.	*3,061
		Box Elder Creek, East Tributary	Interstate Highway 90—at centerline	*3,034
		Box Elder Creek, West Tributary	Hillview Drive (downstream crossing)—at centerline	*3,031
			U.S. Government Railroad—90 feet downstream from centerline	*3,043
			U.S. Government Railroad—70 feet upstream from centerline	*3,049
			South Gate Drive—20 feet upstream from centerline	*3,057
		Box Elder Creek	Intersection of Douglas Road and Morningside Road	#2
Maps available at City Hall, Box Elder, South Dakota.				
Send comments to: Honorable Louis G. Klein, Mayor, City of Box Elder, City Hall, Box 27, Box Elder, South Dakota 57719.				
South Dakota	New Underwood (Town), Pennington County.	Box Elder Creek	Most downstream corporate limits	*2,840
			Most upstream corporate limits	*2,844
		Unnamed Tributary to Box Elder Creek.	Elm Street—20 feet upstream from centerline	*2,841
			South Ash Creek—20 feet upstream from centerline	*2,846
			Box Elder Street—40 feet upstream from centerline	*2,851
			Most upstream corporate limits	*2,861
Maps available at Town Hall, Pine Street, New Underwood, South Dakota.				
Send comments to: Mr. C. S. Batchelder, Chairman, Town Board of Trustees, Town of New Underwood, Box 186, New Underwood, South Dakota 57761.				
South Dakota	Pierre (City), Hughes County	Hilgers Gulch	Confluence with Missouri River	*1,427
			Wells Avenue—centerline	*1,466
			Church Street—50 feet downstream from centerline	*1,486
			U.S. Highway 14/83-200 feet upstream from centerline	*1,608
			Most upstream corporate limits—at centerline	*1,639
Maps available at City Hall, 222 East Dakota Avenue, Pierre, South Dakota.				
Send comments to: Honorable Clint Gregory, Mayor, City of Pierre, City Hall, P.O. Box 1253, Pierre, South Dakota 57501.				

(National Flood Insurance Act of 1968 (Title XIII of Housing and Urban Development Act of 1968), effective January 28, 1969 (33 FR 17804, November 28, 1968), as amended (42 U.S.C. 4001–4128); Executive Order 12127, 44 FR 19367; and delegation of authority to Federal Insurance Administrator, 44 FR 20963.)

Issued: July 12, 1979.

Gloria M. Jimenez,

Federal Insurance Administrator.

[FR Doc. 79-22501 Filed 7-20-79; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

Coast Guard

[46 CFR Parts 160 and 163]

[CGD 74-140]

Vessel Equipment Specifications; Pilot Hoist, Pilot Ladder, and Chain Ladder

AGENCY: Coast Guard, DOT.

ACTION: Proposed rules.

SUMMARY: The Coast Guard proposes to adopt a new safety equipment specification for pilot hoists and to revise the existing specifications for pilot ladders and chain ladders. Recomended standards for pilot hoists and pilot ladders were adopted by the Inter-Governmental Maritime Consultative Organization in 1973. These proposed regulations incorporate design and testing requirements in the IMCO resolutions, and they also modify the existing specification for chain ladders in order to give manufacturers more flexibility in designing equipment. These regulations would apply only to U.S. vessels. The principal effect of these regulations, if adopted, would be to provide for greater safety and security of pilots and other persons that board vesels away from a dock.

DATES: Comments must be received on or before September 21, 1979.

ADDRESSES: 1. Comments should be submitted to the Commandant (G-MC/81) (CGD 74-140), U.S. Coast Guard, Washington, D.C. 20590. Comments will be available for examination at the Marine Safety Council (G-CMC/81), Room 8117, Department of Transportation, Nassif Building, 400 Seventh Street, S.W., Washington, D.C. 20590.

2. Copies of the IMCO Resolutions, technical standards, and draft evaluation for these proposed regulations are available for examination at the Marine Safety Council.

FOR FURTHER INFORMATION CONTACT: Robert L. Markle, Office of Merchant Marine Safety, U.S. Coast Guard, Washington, D.C. 20590 (202-426-1444).

SUPPLEMENTARY INFORMATION: Interested persons are invited to participate in this proposed rule making, by submitting written views, data, or arguments. Persons submitting comments should include their names and addresses, identify this notice (CGD 74-140) and the specific section of the proposal to which their comments apply, and give reasons for the comments. The proposal may be changed in light of comments received. All comments received before the expiration of the comment period will be considered before final action is taken on this proposal. No public hearing is planned but one may be held at a time and place to be set in a later notice in the Federal Register if requested in writing by an interested person raising a genuine issue and desiring to comment orally at a public hearing.

Drafting Information

The principal persons involved in drafting this proposal are: Robert L. Markle, Project Manager, Office of Merchant Marine Safety, and William R. Register, Project Attorney, Office of the Chief Counsel.

Discussion of Proposed Regulations

a. General

1. These proposed regulations revise the existing specifications for pilot ladders and chain ladders and add a new specification for pilot hoists. Pilot hoists and pilot ladders are items of vessel equipment used in routine boarding of pilots and other persons when away from the dock. Chain ladders are items of lifesaving equipment that are intended for emergency use in boarding lifeboats and life rafts.

2. The existing specifications for pilot ladders and chain ladders are in Part 160 of Title 46. However, in the proposed regulations the specifications for pilot ladders, and the new specification for pilot hoists, have been placed in Part 163. The specification for chain ladders has been retained in Part 160.

3. The proposed specifications for pilot ladders and pilot hoists are based primarily on Resolutions A.263(VIII) and A.275(VIII) adopted by the Inter-Governmental Maritime Consultative Organization (IMCO) in 1973. The Coast Guard actively participated in developing these resolutions.

4. Pilot hoists have been used on vessels for several years. Also, letters of approval have been issued for pilot hoists designs that meet guidelines developed before the IMCO Resolution on pilot hoists was adopted.

5. In addition ot the specifications proposed in this notice, the Coast Guard is currently preparing proposed regulations governing the installation, maintenance, and use of pilot hoists, chain ladders, and pilot ladders on vessels. The additional regulations will be based upon similar provisions in IMCO Resolutions A.263(VIII) and A.275(VIII).

6. The proposed specifications include a requirement that approval and production tests be conducted by or under the supervision of an independent laboratory. In the existing specifications for chain ladders and pilot ladders, these tests are done by the manufacturer under the supervision of a Coast Guard marine inspector. The use of independent labs is proposed as a measure to free Coast Guard inspectors for other duties. However, the Coast Guard would retain the ultimate responsbility for design, review, and approval of the equipment. The proposed testing procedures are similar to those which have been in effect for several years for portable fire extinguishers and for some personal flotation devices. The use of independent laboratories would result in additional approval and production costs, which are described in the draft evaluation for these proposed regulations.

7. The Coast Guard has recently proposed general approval procedures, production inspection and test procedures, and standards for accepting independent laboratories for testing certain equipment requiring Coast Guard approval. These proposed procedures were published in the Federal Register of October 23, 1978 (43 FR 49440-45). The proposed procedural rules for pilot hoists, chain ladders, and pilot ladders are included in, or are consistent with, the general procedures published on October 23, 1978. The general procedures, however, also contain additional requirements not found in the proposed rules for pilot hoists, chain ladders, and pilot ladders. In particular, § 159.007-13 of the general procedures includes record keeping requirements that must be met if production inspections and tests are required for approval equipment. If these record keeping requirements are adopted as final rules, they would also apply to pilot hoists, chain ladders, and pilot ladders. A copy of the proposed general procedures may be obtained from the Commandant (G-MMT-3/83) at the address listed under ADDRESSES in this preamble. If the proposed general procedures are adopted as final rules, redundant procedures in the regulations for pilot hoists, chain ladders, and pilot ladders will be removed.

b. Chain Ladders

8. Several of the proposed changes to the chain ladder specification are editorial in nature. These changes have been made to provide a clearer presentation of the specification. The substantive changes to the specification include (1) deletion of existing provisions that prescribe the dimensions of spacer ears, (2) changing the required clearance between suspension members from 480 mm (19 in.) to 400 mm (16 in.), and (3) addition of a requirement for each ladder step to be marked with identification and approval information. The purpose of the deletions is to provide manufacturers with greater flexibility in selection of design detail. The revised clearance is the same as the clearance required for pilot ladders and for rigid ladders and platforms on pilot hoists. The requirement that each step be marked is proposed to facilitate the Coast Guard vessel inspection process. In the existing specification, marking information is required only on every fourth step; and, as a result, it has not been possible during vessel inspections to tell whether each step of an approved ladder meets the requirements of the specification.

9. Type approvals that are currently in effect for chain ladders would remain in effect after adoption of the revised specification. However, manufacturers holding current approvals would have to begin marking each step of a ladder constructed after the effective date of the revised specification.

c. Pilot Hoists

10. The proposed pilot hoist specification incorporates most of the design requirements in IMCO Resolution A.275(VIII). However, there are two principal modifications. Proposed § 163.002-21(c)(4) requires that the speed of a lift platform or rigid ladder on a hoist be between 15 and 21 meters per minute; whereas, the upper limit in the IMCO Resoltion is 30 meters per minute. Also, the proposed specification does not include the IMCO provision that a pilot hoist be capable of efficient operation under conditions of vibration likely to be experienced on a vessel. A minimum speed of 21 meters per minute was selected since greater speeds can create a sense of insecurity for the rider. A hoist designed in accordance with the proposed specification should be able to perform reliably under shipboard vibration conditions.

11. The pilot hoist specification contains, in addition to the requirements in the IMCO Reslution, requirements for lift platforms and the following additional provisions:

a. Proposed § 163.002-11. This section contains materials requirements the purpose of which are to provide for effective corrosion resistance and dependable hoist operation in a marine environment.

b. Proposed § 163.002-13(d). This paragraph requires that the minimum breaking strength of load carrying parts be 6 times the stress imposed on the part by the working load during operation of the hoist. This factor of safety is the same as that required for other lifesaving devices such as lifeboat winches and davits.

c. Proposed § 163.002-13(h). This paragraph requires that a portable pilot hoist have an interlock that prevents movement of its ladder or lift platform when the hoist is not installed.

d. Proposed §§ 163.002-13(p) and 163.002-21(c)(8). These paragraphs contain requirements for the hand-operated device used in raising and lowering the ladder or lift platform on a hoist.

e. Proposed § 163.002-13(t). This paragraph requires in part that a hoist with suspension cables be arranged so that the ladder or lift platform remains level and stationary if one of the cables breaks.

f. Proposed § 163.002-13(u). This paragraph requires in part that the cable drum on a hoist be designed for one level wind of wrap. This requirement is the same as that imposed on cable drums in lifeboat winches.

g. Proposed § 163.002-21(c)(1). This paragraph contains requirements concerning rung strength of a rigid ladder. These requirements are the same as those contained in the proposed pilot ladder specification.

d. Pilot Ladders

12. The proposed pilot ladder specification incorporates, with one principal modification, the design specifications for pilot ladders in IMCO Resolution A.263(VIII), Annex VII. The modification is as follows: Proposed §§ 163.003-11(d) and 163.003-13(c)(1) require that the four lowest steps in a pilot ladder be made of rubber or plastic; whereas, the IMCO Resolution makes rubber steps (and steps of other suitable material) optional items. A requirement to have rubber or plastic steps is proposed since they can withstand the abuse to which the lower steps of a pilot ladder are subjected better than wooden steps can. Both the proposed regulations and the IMCO Resolution, however, require that the remaining steps in the ladder be made of wood since wood provides a better step surface than rubber or plastic.

13. The pilot ladder specification, in addition to incorporating the IMCO requirements, contains requirements for plastic materials used in ladder components and makes provision for attaching a pilot ladder to a pilot hoist. The proposed specification also retains the existing requirements for wooden and metal components and modifies other existing requirements as follows:

a. The existing specification provides for a single rope thimble at the top of each suspension member and, thus, additional rope is necessary to secure the ladder to a vessel. If the additional rope is not as strong as the rope in the ladder, there is the danger that it could break and allow the ladder to fall. Accordingly, proposed § 163.003-13(b) requires that the top of a pilot ladder have extended suspension members and eyes for securing the ladder to anchor points on the vessel.

b. Proposed § 163.003-25 contains revisions to the existing marking requirements for pilot ladders. These revisions are the same as those previously explained for chain ladders.

c. Proposed § 163.003-13(b)(5) would change the required clearance between suspension members from 480 mm (19 in.) to 400 mm (16 in.). This change makes the clearance requirement consistent with the provision in IMCO Resolution A.263(VIII) that an overall length of the step of at least 480 mm (19 in.) is acceptable. The requirement for overall length is in proposed § 163.003-13(c)(4).

d. Proposed § 163.003-21(c)(1) would change the existing strength test for pilot ladder steps to require use of a test load of 900 kg (2000 lb.) instead of the 315 kg (700 lb.) load now required. This change would impose the same strength standards proposed in §§ 163.002-13(d), 163.002-15, and 163.002-21(c)(1) for stepping surfaces on pilot hoist platforms and rigid ladders.

14. As provided in proposed § 163.003-29, approval certificates currently in effect for pilot ladders would terminate upon the effective date of the revised specification. Termination would be necessary since the revised specification significantly upgrades the quality, safety features, and design of pilot ladders. However, the regulations currently under preparation to require use of pilot ladders on vessels contain a provision that would allow the use of pilot ladders approved before the effective date of the revised specification as long as the ladders remained in serviceable condition.

Draft Evaluation

15. These regulations are considered to be "nonsignificant" and, accordingly, a draft evaluation has been prepared as required by the Regulatory Policy and Procedures of the Department of Transportation (44 FR 11040–11045). The DOT Order requires that each evaluation include an economic analysis which quantifies to the extent practicable, both the estimated cost of the regulations to the private sector, consumers, and Federal, State and local governments, as well as the anticipated benefits and impacts of the regulations.

16. The proposed regulations would result in an estimated initial expense of $125,850 and an estimated annual expense of $81,900 dollars to the shipping industry and manufacturers. These expenses include independent lab costs. It is expected that independent lab costs would be about $450 for approval testing (except pilot hoists which would be about $600) and about $450 for each round of production testing. The primary benefits to be derived from this proposal would be greater safety and security for pilots and other persons that board vessels away from the dock, and the freeing of Coast Guard marine inspectors from factory inspection duties, thus, making them available for other marine inspection duties.

In consideration of the foregoing, the Coast Guard proposes to amend Chapter I of title 46, Code of Federal Regulations, as follows:

1. Revise Subpart 160.017 to read as follows:

Subpart 160.017—Chain Ladder

Authority: R.S. 4405 as amended (46 U.S.C. 375), R.S. 4417a, as amended (46 U.S.C. 391a) R.S. 4462, as amended (46 U.S.C. 416) R.S. 4488, as amended (46 U.S.C. 481), Sec. 6(b), 80 Stat. 937 (49 U.S.C. 1655(b)); 49 CFR 1.46.

§ 160.017-1 Scope.

(a) This subpart contains procedures for approval, design requirements, and approval and production tests for chain ladders used on a merchant vessel to get on and off the vessel in an emergency.

(b) The requirements in this subpart apply to a chain ladder designed for use along a vertical portion of a vessel's hull.

§ 160.017-7 Independent laboratory.

(a) The approval and production tests in this subpart must be conducted by, or under the supervision of, an independent laboratory.

(b) To be an independent laboratory, a laboratory must—

(1) be regularly engaged in inspecting and testing marine materials and equipment; and

(2) not be owned or controlled by a manufacturer or vendor of chain ladders or by a supplier of materials to the manufacturer.

§ 160.017-9 Approval procedure.

(a) *General.* A chain ladder is approved by the Coast Guard if it meets the requirements of this subpart, and passes the approval tests.

(b) *Application for approval.* An application for approval of a chain ladder must be sent to the Commandant (G-MMT-3/83), U.S. Coast Guard, Washington, D.C. 20590.

(c) *Contents of application.* An application for approval of a chain ladder must include the following:

(1) Two sets of plans describing the ladder.

(2) The name of a proposed independent laboratory and a description of the laboratory's qualifications to conduct or supervise approval tests.

(3) An approval test plan describing in detail the proposed test procedures, apparatus, and facilities.

(d) *Preliminary review.* The Coast Guard examines the information submitted in the application and determines whether the proposed independent laboratory is acceptable to conduct or supervise the approval tests. The Coast Guard notifies the applicant of the results of this examination and determination.

(e) *Approval tests.* The applicant must make arrangements for the approval tests directly with the independent laboratory. Each approval test must be conducted in accordance with § 160.017-21.

(f) *Submission of test report and plans.* After the approval tests are completed, the applicant must send a test report that meets the requirements in § 160.017-23 and three sets of final plans to the Commandant (G-MMT-3/83). Each set of plans must include the following:

(1) An assembly drawing or general arrangement drawing.

(2) Detailed drawings showing components of the ladder.

(3) For each drawing, a bill of materials or parts list containing a description of each component not detailed on the drawing.

(4) A list identifying the current revision and revision date of each drawing submitted.

(5) A detailed description of the quality control procedure used in producing the ladder.

(g) *Final review and approval.* The Coast Guard reviews the test report and plans and advises the applicant whether the ladder is approved. If the ladder is approved, a certificate of approval and one copy of the approved plans are sent to the applicant. The certificate states the longest ladder length for which approval is given.

§ 160.017-11 Materials.

(a) *Suspension members.* Each suspension member of a chain ladder must be galvanized steel chain that is single-loop, weldless, and of a lock-link pattern. The chain must be trade number 7–0 or larger.

(b) *Metal parts.* Each metal part of a ladder must be made of corrosion-resistant metal or of steel galvanized by the hot dip process after the part is formed.

(c) *Wooden parts.* Each wooden part of a ladder must be made of hardwood that is straight-grained and free of knots, checks, honeycomb, or rot, and any other defects affecting its strength or durability.

(d) *Wood preservative.* After each wooden part is formed and finished, it must be treated with pentachlorophenol or copper napthenate-based wood preservative that is water-repellant. The preservative must be applied by at least two brush coats or by one dip coat. At least 24 hours drying time must be allowed between brush coats.

(e) *Lashing rings.* The inside diameter of each lashing ring must be 75 mm (3 in.). The diameter of the rod from which the ring is made must be 9.5 mm (3/8 in.).

§ 160.017-13 Construction.

(a) *General.* Each chain ladder must have two suspension members. Each step in the ladder must be supported at each end by a suspension member. A typical arrangement is shown in Figure 160.017-13(a).

(b) *Suspension members.* Each suspension member must be a continuous length of chain from the top of the ladder to the bottom. The distance between the two suspension members must be at least 400 mm (16 in.). The chain between each top lashing ring and the first step must be long enough so that the distance between the center of the lashing ring and the top of the first step is approximately 600 mm (24 in.).

(c) *Top lashing rings.* A lashing ring must be attached to the top of each suspension member. The means of attachment must be a reverse lock-link shackle.

(d) *Reverse lock-link shackle.* Each reverse lock-link shackle must be made of chain of a size and strength that is not less than that of the chain in the attached suspension member. The shackle must be locked to the chain of the suspension member by a button head rivet that is not less than 7 mm (9/32 in.) in diameter. The point of the rivet must be driven over a clinch ring to form a rounded head.

(e) *Bottom lashing rings.* A lashing ring must be attached to the bottom of each suspension member. The means of attachment must be a screw pin anchor shackle.

(f) *Screw pin anchor shackle.* The size of the screw pin anchor shackle (the size of the rod from which the shackle is formed) must be 6.5 mm (¼ in.). The screw pin must be securely peened over the shackle.

(g) *Thimble or wear plate.* A thimble or wear plate must be attached to the following:

(1) Each reverse lock-link shackle where it comes into contact with a top lashing ring.

(2) The bottommost chain link of each suspension member where it comes into contact with an anchor shackle.

(h) *Steps.* Each step of a ladder must have two rungs. The distance between steps must be uniform. This distance must be between 300 mm (12 in.) and 380 mm (15 in.).

(i) *Rungs.* Step rungs must meet the following requirements:

(1) Each rung must be wooden.

(2) Rung width must be at least 40 mm (1½ in.) and rung thickness must be at least 25 mm (1 in.) as shown in Figure 160.017–13(a).

(3) Each edge of a rung other than edges along either end must be rounded or chamfered.

(4) The distance between rungs in each step must be uniform as shown on Figure 160.017–13(a) top view. This distance must be between 40 mm (1½ in.) and 65 mm (2½ in.).

(5) Each rung must be attached to a spacer ear by a clip (as shown in Figure 160.017–13(a) top view) or other method that prevents the rung from rotating and that supports it in a horizontal position when the ladder is hung vertically.

(j) *Spacer ears.* Spacer ears must meet the following requirements:

(1) All spacer ears on a ladder must be the same size and shape.

(2) The top and bottom of each spacer ear must be attached to a suspension member.

(3) The top point of attachment must be at least 100 mm (4 in.) above the top surfaces of the rungs attached to the spacer ear.

(4) Each spacer ear must have a smooth finish and each edge must be rounded or chamfered.

(5) Each spacer ear made of sheet metal must be stiffened by one or more formed ribs to prevent the ear from bending and each edge must be turned or rolled to form a flange.

(6) Each cut made in a sheet metal ear for forming purposes must have a hole at each end to prevent point stresses. However, connecting cuts may be joined by a curved cut in lieu of drilling a hole.

(k) *Fasteners.* Wood screws, sheet metal screws, and nails must not be used in a chain ladder. Each bolt used must have a nut and the end of the bolt must be peened over the nut.

(l) *Workmanship.* A ladder must not have splinters, burrs, sharp edges, corners, projections, or other defects that could injure a person using the ladder.

BILLING CODE 4910-14-M

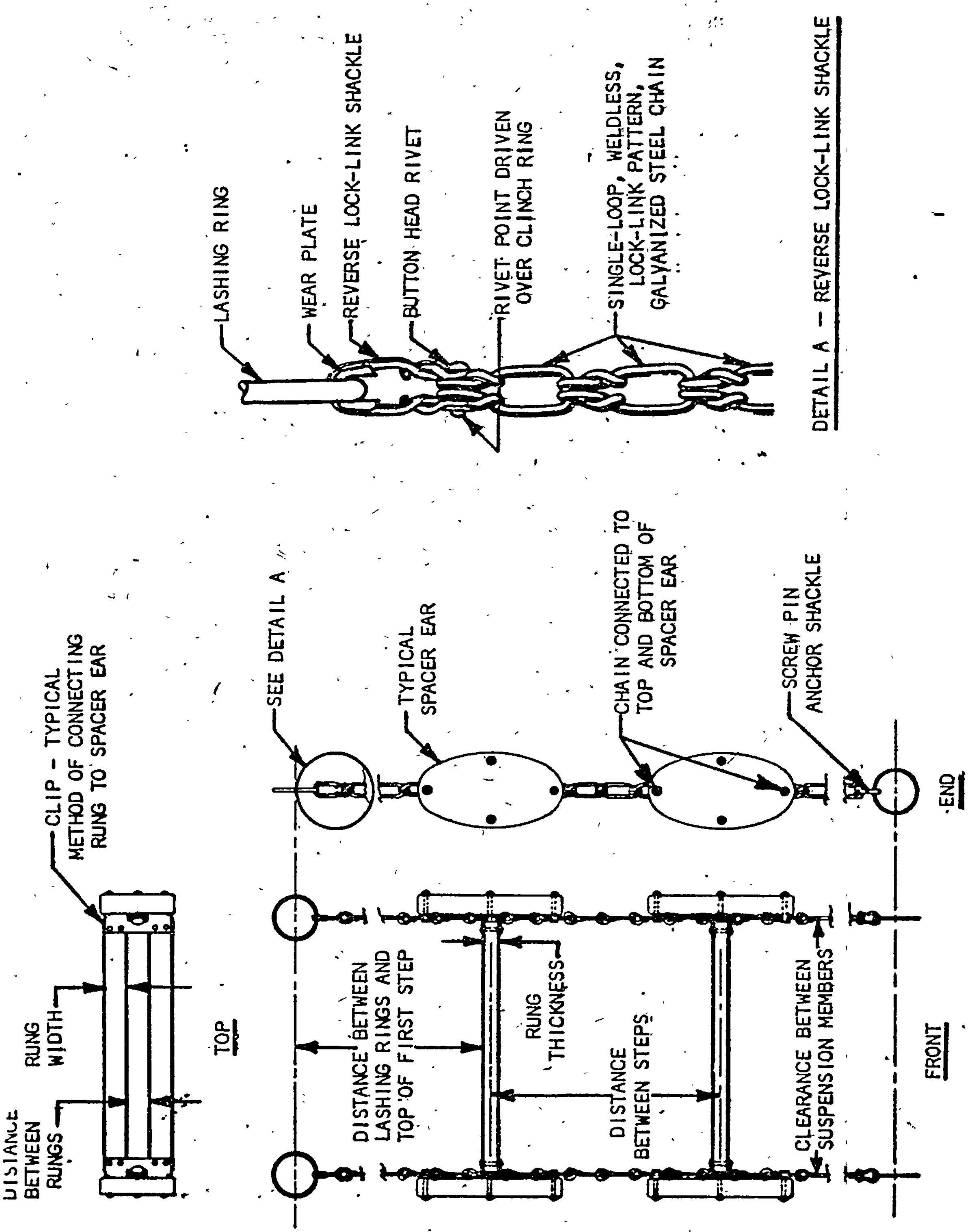


FIGURE 160.017-13(a).
TYPICAL CHAIN LADDER ARRANGEMENT

BILLING CODE 4910-14-C

§ 160.017-15 Performance.

(a) Each chain ladder must be capable of being rolled up for storage.

(b) Each ladder when rolled up must be able to unroll freely and hang vertically.

§ 160.017-17 Strength.

(a) Each chain ladder must be designed to pass the approval tests in § 160.17-21.

§ 160.017-21 Approval tests.

(a) *General.* Each approval test must be conducted on a ladder of the longest length for which approval has been requested. If a ladder fails one of the tests in this section, the cause of the failure must be identified and any needed changes made. After a test failure and any design change, the failed test, and any other previously completed tests affected by the design change, must be rerun.

(b) *Visual examination.* Before starting the tests described in this section, an assembled chain ladder is examined for evidence of noncompliance with the requirements in §§ 160.017.11, 160.017-13, and 160.017-15.

(c) The following approval tests must be conducted:

(1) *Strength test #1.* An assembled ladder is supported so that a static load, if placed on any of its steps, would exert a force both on the step and each suspension member. A static load of 315 kg (700 lb.) is then placed on one step for at least one minute. The load must be uniformly distributed over a contact surface that is approximately 100 mm (4 in.) wide. The center of the contact surface must be at the center of the step. This test is performed on six different steps. No step may break, crack, or incur any deformation that remains after the static load is removed. No attachment between any step and a suspension member may loosen or break during this test.

(2) *Strength test #2.* A ladder is suspended vertically to its full length from its top lashing rings. A static load of 900 kg (2000 lbs.) is then applied to the bottom lashing rings so that it is distributed equally between the suspension members. The suspension members, lashing rings, and spacer ears must not break, incur any elongation or deformation that remains after the test load is removed, or be damaged in any other way during this test.

(3) *Strength test #3.* A rolled-up ladder is attached by its top lashing rings to anchoring fixtures in a location away from any wall or structure that would prevent it from falling freely, and where it can hang to its full length vertically. The ladder when dropped must unroll freely. When unrolling the ladder, its steps and attachments must not become cracked, broken, or loosened. Other similar damage making the ladder unsafe to use must likewise not occur.

§ 160.017-23 Test report.

(1) After the approval tests are completed, a test report must be prepared by the independent laboratory or by the applicant. If the report is prepared by the applicant, its accuracy must be certified by the independent laboratory.

(b) The test report must contain—

(1) The name and address of the applicant;

(2) The name and address of the independent laboratory;

(3) A detailed description of the test procedure and apparatus used;

(4) Detailed test results including all data recorded and a description of each test failure and each other discrepancy;

(5) The observations made during visual examination of the ladder;

(6) The date and location of testing;

(7) The name of each test participant and observer; and

(8) Photographs showing at least one overall view of the ladder and enough additional views to show all major design details, test apparatus, and each failure that occurs during testing.

§ 160.017-25 Marking.

(a) Each chain ladder step manufactured under Coast Guard approval must be branded or otherwise permanently and legibly marked on the bottom with—

(1) The name of the manufacturer;

(2) The manufacturer's brand or model designation;

(3) The lot number of date of manufacture; and

(4) The Coast Guard approval number.

§ 160.017-27 Production tests and examination.

(a) *General.* Each ladder manufactured under Coast Guard approval must be tested in accordance with this section. Steps that fail testing may not be marked with the Coast Guard approval number and each assembled ladder that fails testing may not be sold as Coast Guard approved.

(b) *Test #1: Steps.* Steps must be separated into lots of 100 steps or less. One step from each lot must be selected at random and tested as described in § 106.017-21(c)(1), except that the step may be supported at the points where it would be attached to suspension members in an assembled ladder. If the step fails the test, ten more steps must be selected at random from the lot and tested. If one or more of the ten steps fails the test, each step in the lot must be tested.

(c) *Test #2: Ladders.* Assembled ladders must be separated into lots of 20 ladders or less. One ladder must be selected at random from the ladders in the lot. The ladder selected must be at least 3 m (10 ft.) long or, if each ladder in the lot is less than 3 m long, a ladder of the longest length in the lot must be selected. The ladder must be tested as prescribed in § 160.017-21(c)(2), except that only a 3 m section of the ladder need be subjected to the static load. If the ladder fails the test each other ladder in the lot must be tested.

(d) *Independent laboratory.* Each production test must be conducted or supervised by an independent laboratory acceptable to the Commandant. However, if a test is performed more than 4 different times per year, laboratory participation is required only 4 times per year. If the laboratory does not participate in all tests, the times of laboratory participation must be as selected by the laboratory. The times selected must provide for effective monitoring throughout the production schedule.

(e) *Visual examination.* The visual examination described in § 160.017-21(b) must be conducted as a part of each production test.

(f) *Report of production testing.* A manufacturer of approved chain ladders must prepare and submit to the Commandant (G-MMT-3/83) an annual report of production testing conducted at his facility during the year. The accuracy of tests and examinations conducted by or under supervision of an independent laboratory must be certified by the laboratory.

(g) *Content of report.* Each report must specify the number of lots tested, the lots tested by or under supervision of the independent laboratory, and the dates of laboratory testing. Additional detail is not required, except that a detailed description of each failure and discrepancy observed must be included in the report.

PART 163—CONSTRUCTION

2. A new Subpart 163.002 is added to Part 163 to read as follows:

Subpart 163.002—Pilot Hoist

Authority: R.S. 4405 as amended (46 U.S.C. 375), R.S. 4417a, as amended (46 U.S.C. 391a) R.S. 4462, as amended (46 U.S.C. 416) R.S. 4488, as amended (46 U.S.C. 481), Sec 6(b), 80 Stat. 937 (49 U.S.C. 1655(b)); 49 CFR 1.46

§ 163.002-1 Scope.

(a) This subpart contains approval procedures, design requirements, and approval and production tests for pilot hoists used on merchant vessels.

(b) The requirements in this subpart apply to a pilot hoist designed for use along a vertical portion of a vessel's hull.

§ 163.002-3 Applicable technical regulations.

(a) This subpart makes reference to the following Coast Guard regulations in this chapter:

(1) Subpart 58.30 (Fluid Power and Control Systems).

(2) Section 94.33-10 (Description of Fleet Angle).

(3) Part III (Electrical System, General Requirements).

(4) Subpart 163.003 (Pilot Ladder).

§ 163.002-5 Definitions.

(a) "Maximum persons capacity" means—

(1) If the hoist has a rigid ladder, one person; or

(2) If the hoist has a platform, one person per square meter (10.75 sq. ft.) of fraction thereof of platform area (including hatch area);

(b) "working load" means the sum of the weights of—

(1) The rigid ladder or lift platform, the suspension cables (if any) and the pilot ladder on a pilot hoist; and

(2) 150 kilograms (330 pounds) times the maximum persons capacity of the hoist; and

(c) "Lift height" means the distance from the lowest step of the pilot ladder on a pilot hoist to the deck of a vessel on which the hoist is designed for installation when—

(1) The suspension cables of the hoist are run out until only three turns of cable remain on each drum; or

(2) If the hoist does not have suspension cables, the ladder or lift platform is in its lowest position.

§ 163.002-7 Independent laboratory.

(a) The approval and production tests in this subpart must be conducted by, or under the supervision of, an independent laboratory.

(b) To be an independent laboratory, a laboratory must—

(1) Be regularly engaged in inspecting and testing marine materials and equipment; and

(2) Not be owned or controlled by a manufacturer or vendor of pilot hoists or by a supplier of materials to the manufacturer.

§ 163.002-9 Approval procedure.

(a) *General.* A pilot hoist is approved by the Coast Guard if it meets the requirements of this subpart and passes the approval tests.

(b) *Application for approval.* An application for approval of a pilot hoist must be sent to the Commandant (G-MMT-3/83), U.S. Coast Guard, Washington, D.C. 20590.

(c) *Contents of application.* An application for approval of a pilot hoist must include the following:

(1) Two sets of plans describing the hoist.

(2) The name of a proposed independent laboratory and a description of the laboratory's qualifications to conduct or supervise approval tests.

(3) An approval test plan describing in detail the proposed test procedures, apparatus, and facilities.

(d) *Preliminary review.* The Coast Guard examines the information submitted in the application and determines whether the proposed independent laboratory is acceptable to conduct or supervise the approval tests. The Coast Guard notifies the applicant of the results of this examination and determination.4

(e) *Approval tests.* The applicant must make arrangements for the approval tests directly with the independent laboratory. Each approval test must be conducted in accordance with § 163.002-21.

(f) *Submission of test report and plans.* After the approval tests are completed, the applicant must send the test report and three sets of final plans to the Commandant (G-MMT-3/83). Each set of plans must include the following:

(1) An assembly drawing or general arrangement drawing.

(2) Detailed drawings showing components of the hoist.

(3) For each drawing, a bill of materials or parts list containing a description of each component not detailed on the drawing.

(4) A list identifying the current revision and revision date of each drawing submitted.

(5) A detailed description of the quality control procedure used in producing the hoist.

(6) A copy of the manual described in § 163.002-17(c).

(g) *Final review and approval.* The Coast Guard reviews the test report and plans and advises the applicant whether the pilot hoist is approved. If the hoist is approved, a certificate of approval and one copy of the approved plans are sent to the applicant. The certificate lists the working load, lift height, and maximum persons capacity of the hoist for which approval is given.

(h) *Approval of alternative designs.* A pilot hoist that does not meet the materials, construction, or performance requirements of this subpart may be approved if the application and any approval tests prescribed by the Commandant in place of or in addition to the approval tests required by this subpart, show that the alternative materials, construction, or performance is at least as effective as that specified by the requirements of this subpart.

§ 163.002-11 Materials.

(a) *Gears.* Each gear in a pilot hoist must be made of machine cut steel or machine cut bronze.

(b) *Suspension cables.* Each suspension cable on a pilot hoist must be a corrosion-resistant wire rope other than galvanized wire rope. Each cable must have a diameter of not less than 4.5 mm (3/16 in.).

(c) *Corrosion resistant materials.* Materials of a pilot hoist that are not in watertight enclosures must be—

(1) Corrosion resistant or must be treated to be corrosion resistant; and

(2) Galvanically compatible with each other adjoining material.

(d) *Aluminum alloys.* Any aluminum alloy that contains more than 0.6 percent copper must not be used in a structural component or in any other hoist component subject to stress.

§ 163.002-13 Construction.

(a) *General.* Each hoist must have a rigid ladder or a lift platform on which a person being raised or lowered may stand.

(b) *Spreader.* Each hoist must have a spreader or other device to prevent twisting of its ladder or lift platform. If a spreader is provided, it must be at least 1800 millimeters (5 feet, 10 inches) long.

(c) *Rollers.* The rigid ladder or lift platform on a pilot hoist and the ends of its spreader (if a spreader is provided) must have rollers at each point of contact with the vessel that allow the ladder or platform to move smoothly over the side of the vessel.

(d) *Load carrying parts.* Each load carrying part of a pilot hoist must be designed to have a minimum breaking strength of at least six times the load imposed on the part by the working load during operation of the hoist.

(e) *Exposed moving parts.* Each exposed moving part of a pilot hoist that poses a hazard to personnel must have a screen or guard.

(f) *Nonfunctional sharp edges and projections of excessive length.* A pilot hoist must not have nonfunctional sharp edges and must not have fastening devices or other projections of excessive length.

(g) *Installation requirements.* Each pilot hoist must be designed to allow—

(1) Its installation along the edge of a deck at a vertical portion of the hull;

(2) Its installation on the deck in a manner that does not require use of the vessel's side rails for support; and

(3) Unobstructed passage between the ladder or lift platform of the hoist and the deck of a vessel.

(h) *Deck interlock for portable hoist.* A pilot hoist, if portable, must have a deck interlock that prevents movement of the ladder or lift platform when the hoist is not installed.

(i) *Power source.* Each hoist must be designed to operate on electric, pneumatic, or hydraulic power or a combination of these.

(j) *Electrical equipment.* Electrical equipment of a pilot hoist must meet the electrical engineering regulations in Part 111 of this chapter. The operating voltage of electrical equipment on the ladder or lift platform of a pilot hoist must not exceed 25 volts.

(k) *Pneumatic and hydraulic equipment.* Pneumatic and hydraulic equipment of a pilot hoist must comply with the marine engineering regulations of Subpart 58.30 of this chapter. Each pneumatically powered hoist must have a water trap, air filter, air regulator, pressure gauge, and oil lubricator in the air line between the vessel's compressed air source and the pneumatic motor.

(l) *Hoist control lever.* Each pilot hoist must have a control lever for raising and lowering its ladder or lift platform. Movement of the lever upward or toward the operator must result in upward movement of the ladder or lift platform. Movement of the control in the opposite direction must result in downward movement of the ladder or lift platform. The control must be designed so that when released by the operator the ladder or lift platform stops immediately.

(m) *Emergency disconnect device.* Each pilot hoist must have a switch or valve for disconnnecting the main power source in an emergency.

(n) *Power indicator.* Each pilot hoist must have an indicator to show the operator when power is being supplied to the hoist.

(o) *Arrangement of controls and power indicator.* The hoist control lever, the emergency disconnnect device, and the power indicator on a pilot hoist must be arranged so that the hoist operator, when standing, can view all movement of the ladder or lift platform while using this equipment.

(p) *Hand-operated device and interlock.* Each pilot hoist must have a hand-operated device for raising and lowering its ladder or lift platform. The device must be operable from a standing position. The hoist must have an interlock that prevents simultaneous operation of its hand-operated device and its power source. Any removable hand gear, crank, or wheel of the hand-operated device must be securely stowed on the hoist.

(q) *Upper position stop.* Unless a hoist has a pneumatic motor that stalls at the end of cable travel without jarring, jerking, or damaging the hoist, it must have one or more limit switches or valves that stop the ladder or lift platform at its upper end of travel without jarring, jerking, or damaging the hoist.

(r) *Means of lubrication.* Each hoist must have a means to lubricate its bearings. Each worm gear must operate in an oil bath. Each lubricant enclosure must be designed so that it can be readily filled, drained, and checked for lubricant level.

(s) *Machinery housing.* Each machinery housing on a pilot hoist except gear boxes and other enclosures that retain lubricants, must have one or more inspection ports that permit examination of all internal moving parts. The cover of each covered inspection port must be removable with common tools or without tools. Each machinery housing, except gear boxes and other enclosures that retain lubricants, must be open at the bottom or must have a drain to prevent moisture accumulation.

(t) *Suspension cable.* If a hoist has supension cables, at least 2 cables must be provided and they must be arranged so that the ladder or lift platform remains level and stationary if one of the cables breaks. Each cable must be arranged to lead fair in a 15 degree vessel list toward the side of the vessel on which the hoist is installed. The devices for attaching the cables to their winch drums must be capable of supporting 2.2 times the working load with the cables run all the way out.

(u) *Sheaves and drums.* Each sheave and each winch drum for a suspension cable on a pilot hoist must be of a size recommended by the cable supplier for the diameter and construction of the cable. Each drum must be designed to accept one level wind of wrap. The fleet angle of a grooved drum must not exceed 8 degrees, and the fleet angle of a non-grooved drum must not exceed 4 degrees.

Note.—The term "fleet angle" is defined in § 94.33-10 of this chapter.

(v) *Rigid ladder.* A rigid ladder on a pilot hoist must have thermally insulated handholds and a padded backrest so that the person being raised or lowered may firmly brace himself or herself between the ladder and the backrest. The ladder must be at least 2.5 m (100 in.) long from the bottom rung to the top of the handholds.

(w) *Ladder rungs.* Each rigid ladder must have at least six rungs, each with a non-skid surface. The stepping surface of each rung must be not less than 115 millimeters (4½ inches) wide and not less than 400 millimeters (16 inches) long. The distance between rungs must be uniform. This distance must be between 300 millimeters (12 inches) and 380 milimeters (15 inches).

(x) *Platform railing.* A lift platform on a pilot hoist must be enclosed by a guardrail that has a diameter of between 30 millimeters (1¼ inches) and 75 millimeters (3 inches). The center of the guardrail must be at least 900 millimeters (3 feet) above the platform. At least one intermediate rail must be provided between the guardrail and the platform. Each rail must be set back from the edge of the platform at least 50 millimeters (2 inches). Each gate in the rails must have a latch that can keep the gate securely closed.

(y) *Platform floor.* The platform floor of a pilot hoist must have a non-skid surface and must be at least 750 millimeters (30 inches) by 750 millimeters, exclusive of the surface area of any hatch. Each hatch in the platform floor must be at least 750 millimeters (30 inches) by 750 millimeters. Each hatch must have a means to keep it securely positioned both when opened and closed.

(z) *Pilot ladder fittings.* The bottom of the rigid ladder or lift platform on a pilot hoist must have fittings to attach a pilot ladder of the type that meets the requirements of Subpart 163.003 of this chapter. The fittings must be arranged so that—

(1) The distance between the top rung of the pilot ladder and the lift platform or bottom rung of the rigid ladder is between 225 and 400 millimeters (9 and 16 inches);

(2) The steps of the pilot ladder are directly below and in line with the steps of the rigid ladder or edge of the lift platform; and

(3) The pilot ladder can bear on the side of the vessel when in use.

(aa) *Emergency stop switch.* Each pilot hoist must have an emergency stop switch that can be operated by a person on the ladder or lift platform.

(bb) *Fasteners.* Each screw, nut, bolt, pin, key, or other fastening device securing a part of a pilot hoist must have a lock washer, cotter pin, locking device or compound, or other means to prevent the device from loosening.

(cc) *Gears.* Each gear must be keyed to its shaft.

(dd) *Welding.* Each weld must be made using automatic welding equipment or be made by a welder who is qualified by the U.S. Coast Guard, U.S. Navy, American Bureau of Shipping, American Welding Society, American Society of Mechanical Engineers, or other organization that has similar procedures for welder qualifications that are acceptable to the Commandant.

§ 163.002-15 Performance.

(a) Each pilot hoist must have sufficient performance capability to pass the approval tests in § 163.002-21.

§ 163.002-17 Instructions and markings.

(a) *Instruction plates or placards.* Each pilot hoist must have instructions that show its method of operation and lubrication of its working parts. The instructions must be on one or more corrosion-resistant plates, or must be weatherproof placards. The instructions must be attached to the hoist. Each instruction must be in English or must have understandable symbols or pictograms. The operator of the hoist must be able to see and read the operating instructions when to operate the hoist control lever. The lubricating instructions must state the recommended lubricants for the temperature range in which the hoist is designed to operate. The temperature range must be stated in both degrees Celsius and Fahrenheit.

(b) *Marking of controls.* Each control on a pilot hoist and each position of the control must be identified by a marking on the hoist.

(c) *Manual.* Each pilot hoist must have a manual of operating instructions, maintenance and repair instructions, a lubrication chart, a parts list, a list of sources of repair parts, and a log for keeping maintenance records. Each manual must be in English.

§ 163.002-21 Approval tests.

(a) *General.* If a pilot hoist fails one of the tests in this section the cause of the failure must be identified and any needed design changes made. After a test failure and any design change, the failed test, and any other previously completed tests affected by the change, must be rerun.

(b) *Visual examination.* Before starting the tests described in this section an assembled pilot hoist is examined for evidence of noncompliance with the requirements in §§ 163.002-11 and 163.002-13.

(c) The following approval tests must be conducted:

(1) *Rung strength.* If the pilot hoist has a rigid ladder a static load of 900 kilograms (2000 pounds) is applied to the center of a ladder rung for one minute. The load must be uniformly distributed over a 100 millimeter (4 inch) wide contact surface. The test must be repeated using a second ladder rung. The rungs must not break or crack during these tests.

(2) *Platform strength.* If the pilot hoist has a lift platform, the platform is lifted to a level where it is supported only by its suspension components. A static load of 900 kilograms (2000 pounds) is then applied to the center of the platform for one minute. The load must be uniformly distributed over a 100 millimeter (4 inch) square contact surface. The test must be repeated enough additional times so that the load is placed in the center of each hatch cover when in its closed position, and in the center of each area of the platform located between floor supports. The platform must not break or crack during these tests.

(3) *Deck interlock.* If the pilot hoist is portable, it is placed in an uninstalled position. Its hoist control lever is then activated. The deck interlock must prevent movement of the ladder or lift platform when the lever is activated.

(4) *Lifting and lowering speed and level wind.* The hoist is installed in a level operating position and a weight equal to the weight of the pilot ladder plus 150 kg (330 lb.) times the maximum persons capacity of the hoist is placed on its ladder or lift platform. The ladder or lift platform is repeatedly raised and lowered under power operation until a total distance of at least 150 meters (500 feet) has been traversed. The ladder or lift platform is raised and lowered each time through a distance of at least 5 meters (16 feet). The average speed of raising the ladder or lift platform and the average lowering speed during this test must both be between 15 and 21 meters per minute (50 and 70 feet per minute). During the test, each suspension cable must have one level wind of wrap each time it is rewound onto its drum.

(5) *Upper position stop.* The hoist is installed in a level operating position and a weight equal to the weight of the pilot ladder plus 150 kg (330 lb.) times the maximum persons capacity is attached to the hoist. The hoist must be able to raise the weight to the upper limit of travel of the ladder or lift platform and must be able to stop at the upper limit without jarring, jerking, or damage. The test is repeated with no weight on the ladder or lift platform.

(6) *Cable securing device.* If the hoist has suspension cables, it is installed in a level operating position and the cables are run all the way out. A weight equal to 2.2 times the working load is then attached to the cables. The cables must remain securely attached to the drums for at least one minute after the weight has been attached.

(7) *Controls and power indicator.* The hoist is installed in a level operating position and a weight equal to the working load is attached to the hoist. The hoist control lever is then operated with the power both on and off. The lever, when operated, must meet the requirements in § 163.002-13(l). The power indicator must meet the requirements in § 163.002-13(n) during the test. When the power is turned off, the ladder or lift platform must stop immediately and remain stationary until power is turned on. The emergency stop switch on the ladder or lift platform is activated at some point when the ladder or lift platform is being raised or lowered. Upon activation, the ladder or lift platform must stop and remain stationary.

(8) *Hand operation and interlock.* The hoist is installed in a level operating position and a weight equal to the working load is attached to the hoist. The hand operating device is then engaged. One person, when using the hand operated device, must be able to raise and lower the weight through a distance of at least 5 meters (16 ft.) in each direction and must be able to raise and lower it at a speed of at least 1.5 meters per minute (5 ft. per minute). When raising or lowering the hoist with the hand operated device, the power source for the hoist is turned on, or an attempt is made to turn it on. Then, with power source turned off, the hand operated device is disengaged. The power source is then turned on and an

attempt made to engage the hand operated device. The interlock must prevent simultaneous operation of the power source and the hand operated device.

(9) *2.2x overload.* The hoist is installed in a level operating position. Each roller on the ladder or lift platform is placed in contact with a vertical surface. A weight equal to the differece between 2.2 times the working load and the weight of the ladder or lift platform is placed on the ladder or lift platform. The ladder or lift platform is raised through a distance of at least 5 meters (16 feet) and the hoist control lever is then released. The ladder or lift platform must stop without jarring or damage and must hold the weight for at least one minute. The weight is then lowered through a distance of not less than 5 meters (16 feet) and the control lever is then released. The ladder or lift platform must stop within 600 millimeters (2 ft.) of where the hoist was when the lever was released and the ladder or lift platform must remain stationary for at least one minute thereafter. Each roller must move smoothly over the vertical surface without jamming or sliding during the test.

(10) *6x overload.* The hoist is installed in a level operating position. A load of six times the working load is attached to the hoist. (If the hoist has suspension cables, the cables must be run out at least one meter (3 ft.) before adding the load to the hoist). The weight must remain stationary for at least one minute without damage to any part of the hoist. The test is repeated simulating a vessel list of 15 degrees toward the side on which the hoist is installed.

(11) *Level wind suspension cable.* If the hoist has suspension cables, it is installed in a level operating position with the cables wound onto the drums. A weight equal to the working load is attached to the hoist. The cables are run all the way out and then rewound back onto the drums. Each drum and cable is observed for level winding as the cable is wound onto the drum. The test must be repeated with a weight equal to the weight of the rigid ladder or lift platform. In each test, each cable must rewind onto the drum in one level wind of wrap.

§ 163.002-23 Test report.

(a) After the approval tests are completed, a test report must be prepared by the independent laboratory or by the applicant. If the report is prepared by the applicant, its accuracy must be certified by the independent laboratory.

(b) The test report must contain—

(1) The name and address of the applicant;

(2) The name and address of the independent laboratory;

(3) A detailed description of the test procedure and apparatus used;

(4) Detailed test results including all data recorded and a description of each test failure and each other discrepancy;

(5) The observations made during visual examination of the hoist;

(6) The date and location of testing;

(7) The name of each test participant and observer; and

(8) Photographs showing at least one overall view of the hoist and enough additional views to show all major design details, test apparatus, and each failure occurring during testing.

§ 163.002-25 Marking.

(a) Each pilot hoist manufactured under Coast Guard approval must have a corrosion-resistant nameplate. The nameplate must contain the—

(1) Name of the manufacturer;

(2) Manufacturer's brand or model designation;

(3) Working load;

(4) Lift height;

(5) Maximum persons capacity;

(6) Hoist serial number;

(7) Date of manufacture; and

(8) Coast Guard approval number.

(b) The hoist must be permanently and legibly marked with the name of the laboratory that conducted the production tests.

§ 163.002-27 Production tests and examination.

Each pilot hoist manufactured under Coast Guard approval must be tested as prescribed in § 163.002-21(c)(9). The tests must be conducted by an independent laboratory acceptable to the Coast Guard. If the hoist fails the tests its defects must be corrected and retested until it passes. The laboratory must also conduct the visual examination described in § 163.002-21(b). The hoist may not be sold as Coast Guard approved unless it passes testing and unless each defect discovered in the visual examination is corrected.

3. A new Subpart 163.003 is added to Part 163 to read as follows:

Subpart 163.003—Pilot Ladder

Sec.

Authority: R.S. 4405 as amended (46 U.S.C. 375), R.S. 4417a, as amended (46 U.S.C. 391a) R.S. 4462, as amended (46 U.S.C. 416) R.S. 4488, as amended (46 U.S.C. 481), Sec. 6(b), 80 Stat. 937 (49 U.S.C. 1655(b)); 49 CFR 1.46.

§ 163.003-1 Scope.

(a) This subpart contains approval procedures, design requirements, and approval and production tests for a pilot ladder used on a merchant vessel to embark and disembark pilots and other persons when away from the dock.

(b) The requirements in this subpart apply to a pilot ladder designed for use along a vertical portion of a vessel's hull.

§ 163.003-3 ASTM standard.

(a) This subpart makes reference to the following standard of the American Society for Testing and Materials;

ASTM D 1435-75 entitled "Standard Recommended Practice for Outdoor Weathering of Plastics."

(b) Standards of the American Society for Testing and Materials can be obtained from the Society at 1916 Race St., Philadelphia, Pa. 19103.

§ 163.003-7 Independent laboratory.

(a) The approval and production tests in this subpart must be conducted by, or under the supervision of, an independent laboratory.

(b) To be an independent laboratory, a laboratory must—

(1) Be regularly engaged in inspecting and testing marine materials and equipment; and

(2) Not be owned or controlled by a manufacturer or vendor of pilot ladders or by a supplier of materials to the manufacturer.

§ 163.003-9 Approval procedure.

(a) *General.* A pilot ladder is approved by the Coast Guard if it meets the requirements of this subpart and passes the approval tests.

(b) *Application for approval.* An application for approval of a pilot ladder must be sent to the Commandant (G-MMT-3/83), U.S. Coast Guard, Washington, D.C. 20590.

(c) *Contents of application.* An application for approval of a pilot ladder must include the following:

(1) Two sets of plans describing the ladder.

(2) The name of a proposed independent laboratory and a

description of the laboratory's qualifications to conduct or supervise approval tests.

(3) An approval test plan describing in detail the proposed test procedures, apparatus, and facilities.

(d) *Preliminary review.* The Coast Guard examines the information submitted in the application and determines whether the proposed independent laboratory is acceptable to conduct or supervise the approval tests. The Coast Guard notifies the applicant of the results of this examination and determination.

(e) *Approval tests.* The applicant must make arrangements for the approval tests directly with the independent laboratory. Each approval test must be conducted in accordance with § 163.003–21.

(f) *Submission of test report and plans.* After the approval tests are completed, the applicant must send the test report prescribed by § 163.003–23 and three sets of final plans to the Commandant (G–MMT–3/83). Each set of plans must include the following:

(1) An assembly drawing or general arrangement drawing.

(2) Detailed drawings showing components of the ladder.

(3) For each drawing, a bill of materials or parts list containing a description of each component not detailed on the drawing.

(4) A list identifying the current revision and revision date of each drawing submitted.

(5) A detailed decription of the quality control procedure used in producing the ladder.

(g) *Final review and approval.* The Coast Guard reviews the test report and plans and advises the applicant whether the ladder is approved. If the ladder is approved, a certificate of approval and one copy of the approved plans are sent to the applicant. The certificate states the longest ladder length for which approval is given.

§ 163.003–11 Materials.

(a) *Suspension members.* Each suspension member must be mildew-resistant manila rope that has a breaking strength of not less than 24,000 N (5,400 lb.) and a nominal circumference of not less than 60 mm (2¼ in.).

(b) *Wooden parts.* Each wooden part of a pilot ladder must be hardwood that is straight-grained and free from knots, checks, honeycomb, warp, rot, and any other defects affecting its strength or durability.

(c) *Wood preservative.* After each wooden part is formed and finished, it must be treated with pentachlorophenol or copper napthenate-based wood preservative that is water-repellant. The preservative must be applied by at least two brush coats or by one dip coat. At least 24 hours drying time must be allowed between brush coats.

(d) *Molded steps.* Each step made of molded construction must be rubber or resilient plastic.

(e) *Metal parts.* Each metal part must be made of corrosion-resistant metal or of steel galvanized by the hot dip process after the part is formed.

(f) *Plastics.* Each plastic material must be of a type that retains at least 80 percent of its original tensile strength and at least 80 percent of its original impact strength when subjected to the one year outdoor weathering test described in ASTM D 1435.

§ 163.003–13 Construction.

(a) *General.* Each pilot ladder must have two suspension members on each side. Each step must be supported by each suspension member. A typical arrangement is shown in Figures 163.003–13(a)(1) and 163.003–13(a)(2).

(b) *Suspension members.* The suspension members of a pilot ladder must meet the following requirements:

(1) Each suspenson member must be continuous from the top of the ladder to the bottom and must not be painted or otherwise coated or covered.

(2) Except as provided in paragraph (h) of this section—

(i) The top end of one suspension member on each side of a ladder must extend at least 3 m (10 ft.) beyond the top ladder step; and

(ii) The top ends of the other suspension members must be just above the top step and must have an eye splice or thimble large enough to fit two passes of a suspension member.

(3) The top end of each suspension member that does not have an eye splice or thimble must be served with a 25 mm (1 in.) wide band of tarred marline or treated in another equally effective way to prevent fraying.

(4) Each suspension member must be served with a 25 mm (1 in.) wide band of tarred marline immediately above each insert that adjoins the top surface of a ladder step and immediately below each insert that adjoins the bottom surface of a ladder step.

(5) The distance between the suspension members on one side of a ladder and those on the other side must be at least 400 mm (16 in.).

(c) *Steps.* Pilot ladder steps must meet the following requirements:

(1) The four lowest steps must be molded steps and the rest of the steps must be wooden.

(2) The top face of each step must have a rectangular surface that is at least 115 mm (4½ in.) wide and must have grooves that do not retain water and that provide a non-skid surface.

(3) Each step at its thinnest point must be at least 25 mm (1 in.) thick and, in determining this thickness, the depth of the grooves in the non-skid surface and the diameter of any hole extending from one side of the step to the other must not be counted.

(4) Each step must be at least 480 mm (19 in.) long.

(5) The top edges of the sides of each step must be rounded or chamfered.

(6) Each step must be designed so that it can be replaced without unstringing the ladder.

(7) If a step has grooves for its suspension members, the grooves must be in the sides of the step.

(8) The distance between each step must be uniform and this distance must be between 300 mm (12 in.) and 380 mm (15 in.).

(9) Each step on a pilot ladder must have four inserts.

(d) *Inserts.* Step inserts must meet the following requirements:

(1) Each insert must be arranged to guide the suspension members on one side of the ladder from a step to the point where the suspension members are served with tarred marline.

(2) Each insert must be designed to prevent the edges of the step from chafing the suspension members.

(3) The height of each insert must not be more than one-half the width of the step.

(4) Each insert for a wooden step must be bound into place with tarred marline but must not be attached to the step.

(5) Each insert for a molded step must be molded into the step or must be bound into place with tarred marline.

(3) *Spreaders.* Each pilot ladder with 9 or more steps must have one or more spreaders that meet the following requirements:

(1) Each spreader must be at least 1.8 m (70 in.) long.

(2) If a ladder has two or more spreaders, the spreaders must be positioned at intervals of not more than 9 steps.

(3) The lowest spreader on a ladder must be on the fifth step from the bottom.

(f) *Fasteners.* Wood screws and nails must not be used in a pilot ladder. Each bolt must have a nut and the end of the bolt must be peened over the nut.

(g) *Workmanship.* A pilot ladder must not have splinters, burrs, sharp edges, corners, projections, or other defects that could injure a person using the ladder.

(h) *Special arrangements for pilot hoists.* Each pilot ladder produced for use with an approved pilot hoist must have at least 8 steps. The top ends of its suspension members need not have an eye splice or thimble or be arranged as required in paragraph (b) of this section if necessary to permit attaching the ladder to fittings of a particular pilot hoist.

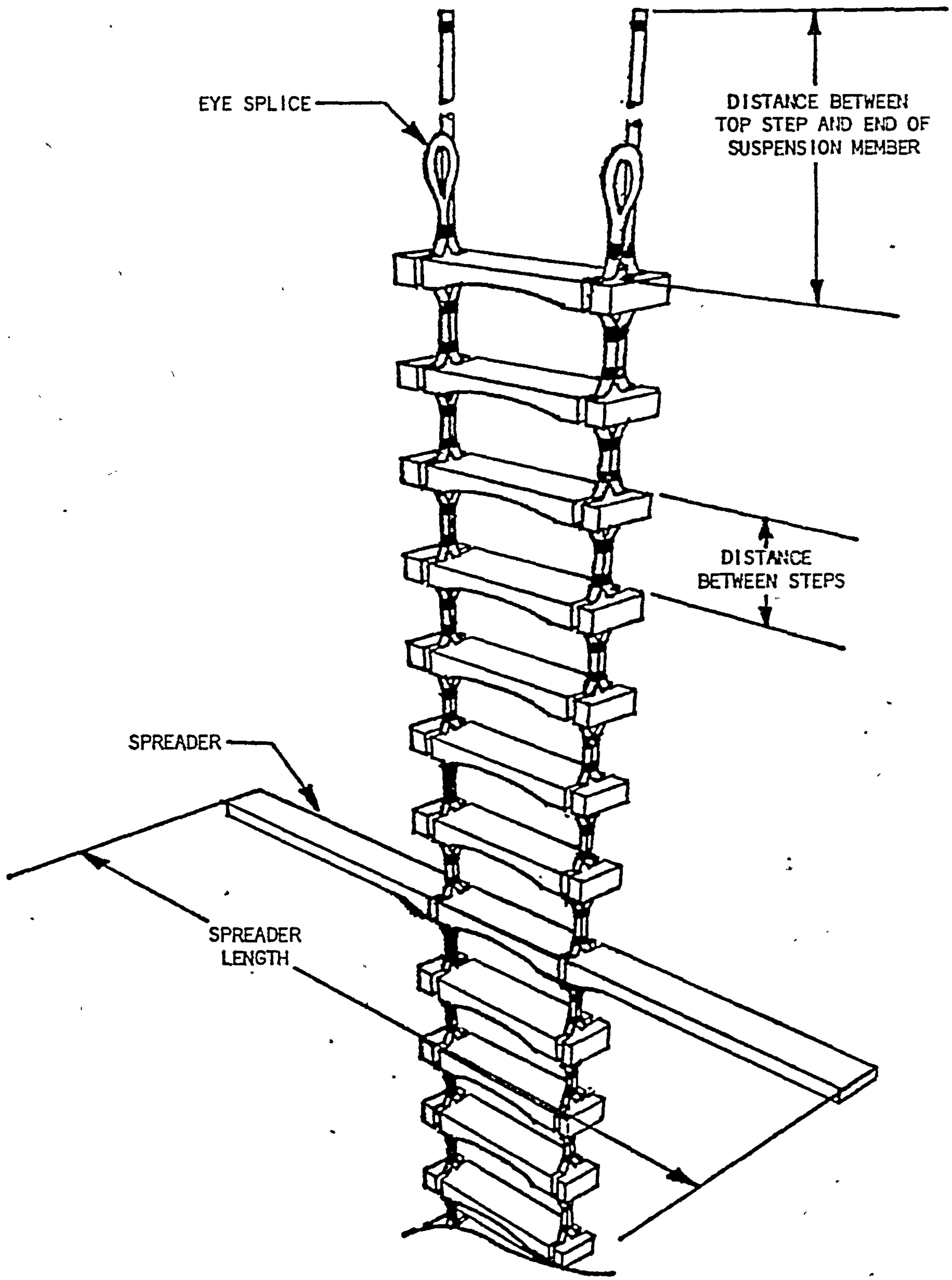


FIGURE 163.003-13(a)(1) TYPICAL PILOT LADDER ARRANGEMENT

BILLING CODE 4910-14-M

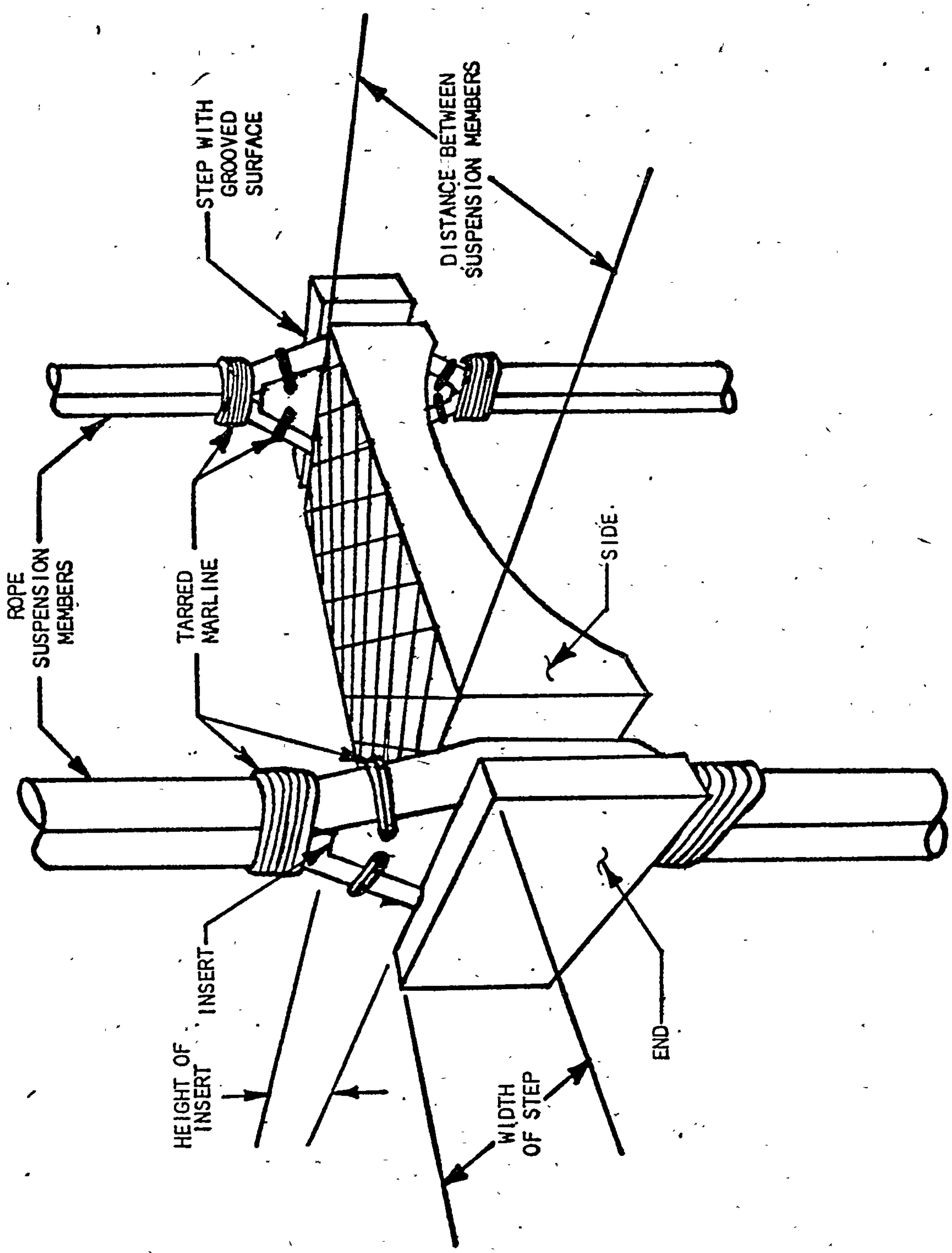


FIGURE 163.003-13(a)(2). TYPICAL PILOT LADDER STEP DETAIL

BILLING CODE 4910-14-C

§ 163.003-15 Performance.

(a) Each pilot ladder must be capable of being rolled up for storage.

(b) Each ladder when rolled up must be able to unroll freely and hang vertically.

(c) Each suspension member must be arranged so that, when the ladder is in use on a vessel, the suspension member cannot come in contact with the vessel's side.

(d) Each step must be arranged so that it can bear on the side of the vessel when the ladder is in use.

§ 163.003-17 Strength.

(a) Each pilot ladder must be designed to pass the approval tests in § 163.003-21.

§ 163.003-21 Approval tests.

(a) *General.* Each approval test must be conducted on a ladder of the longest length for which approval has been requested. If the ladder fails one of the tests, the cause of the failure must be identified and any needed design changes made. After a test failure and any design change, the failed test, and any other previously completed tests affected by the change, must be rerun.

(b) *Visual examination.* Before starting the approval tests, an assembled pilot ladder is examined for evidence of noncompliance with the requirements in §§163.003-11, 163.003-13, and 163.003-15.

(c) The following approval tests must be conducted:

(1) *Strength test #1.* An assembled ladder is supported so that a static load, if placed on any of its steps, would exert a force on both the step and each suspension member. A static load of 900 kg (2000 lb.) is then placed on one step for at least one minute. The load must be uniformly distributed over a contact surface that is approximately 100 mm (4 in.) wide. The center of the contact surface must be at the center of the step. This test is performed on six different steps, one of which must be a molded step. None of the steps may break or crack. No attachment between any step and a suspension member may loosen or break during this test.

(2) *Strength test #2.* An assembled ladder is suspended vertically to its full length. A static load of 900 kg (2000 lb.) is then applied to the bottom step of the ladder so that it is distributed equally between the suspension members. The suspension members, steps, and inserts must not break, incur any elongation or deformation that remains after the test load is removed, or be damaged in any other way during this test.

(3) *Strength test #3.* A rolled up ladder is attached to anchoring fixtures in a location away from any wall or structure that would prevent it from falling freely, and where it can hang to its full length vertically. The ladder when dropped must unroll freely. When unrolling the ladder, its steps and attachments must not become cracked, broken, or loosened. Other similar damage making the ladder unsafe to use must likewise not occur.

§ 163.003-23 Test report.

(a) After the approval tests are completed, a test report must be prepared by the independent laboratory or by the applicant. If the report is prepared by the applicant, its accuracy must be certified by the independent laboratory.

(b) The test report must contain—

(1) The name and address of the applicant;

(2) The name and address of the independent laboratory;

(3) A detailed description of the test procedure and apparatus used;

(4) Detailed test results including all data recorded and a description of each test failure and each discrepancy;

(5) The observations made during visual examination of the ladder;

(6) The date and location of testing;

(7) The name of each test participant and observer; and

(8) Photographs showing at least one overall view of the ladder and enough additional views to show all major design details, test apparatus, and each failure occurring during testing.

§ 163.003-25 Marking.

(a) Each step of a pilot ladder manufactured under Coast Guard approval must be branded or otherwise permanently and legibly marked on the bottom with—

(1) The name of the manufacturer;

(2) The manufacturer's brand or model designation;

(3) The lot number or date of manufacture; and

(4) The Coast Guard approval number.

§ 163.003-27 Production tests and examination.

(a) *General.* Each ladder produced under Coast Guard approval must be tested in accordance with this section. Steps that fail testing may not be marked with the Coast Guard approval number and each assembled ladder that fails testing may not be sold as Coast Guard approved.

(b) *Test No. 1: Steps.* Steps must be separated into lots of 100 steps or less. Wooden steps and molded steps must be placed in separate lots. One step from each lot must be selected at random and tested as described in § 163.003-21(c)(1), except that supports are placed under the step at the points where it would be attached to suspension members in an assembled ladder. If the step fails the test, ten more steps must be selected at random from the lot and tested. If one or more of the ten steps fails the test, each step in the lot must be tested.

(c) *Test No. 2: Ladders.* Assembled ladders must be separated into lots of 20 ladders or less. One ladder must be selected at random from the ladders in each lot. The ladder selected must be at least 3 m (10 ft.) long or, if each ladder in the lot is less than 3 m long, a ladder of the longest length in the lot must be selected. The ladder must be tested as prescribed in § 163.003-21(c)(2), except that only a 3 m section of the ladder need be subjected to the static load. If the ladder fails the test, each other ladder in the lot must be tested.

(d) *Independent laboratory.* Each production test must be conducted or supervised by an independent laboratory acceptable to the Commandant. However, if a test is performed more than 4 different times per year, laboratory participation is required only 4 times per year. If the laboratory does not participate in all tests, the times of laboratory participation must be as selected by the laboratory. The times selected must provide for effective monitoring throughout the production schedule.

(e) *Visual examination.* The visual examination described in § 160.017-21(b) must be conducted as a part of each production test.

(f) *Report of production tests and visual examination.* A manufacturer of approved pilot ladders must prepare and submit to the Commandant (G-MMT-3/83) an annual report of production testing conducted at his facility during the year. The accuracy of tests and examinations conducted by or under supervision of an independent laboratory must be certified by the laboratory.

(g) *Content of report.* Each report must specify the number of lots tested, the lots tested by or under supervision of the independent laboratory, and the dates of laboratory testing. Additional detail is not required, except that a detailed description of each failure and discrepancy observed must be included in the report.

§ 163.003-29 Effective date and status of prior approval.

(a) This subpart becomes effective [90 days after its publication as a final rule].

(b) Approval certificates for pilot ladders issued under Subpart 160.017 terminate on [the effective date prescribed in paragraph (a) of this section.]

(c) Applications for approval of pilot ladders under this subpart will be accepted on and after [date of publication of final rules].

(d) In previous regulations, pilot ladders were referred to as Type I—Rope Suspension Ladders.

(46 U.S.C. 375, 391a, 416, and 481; 49 U.S.C. 1655(b); and 49 CFR 1.46.)

Dated: July 2, 1979.

R. H. Scarborough,

Vice Admiral, U.S. Coast Guard, Acting Commandant.

[FR Doc. 79-22401 Filed 7-20-79; 8:45 am]

BILLING CODE 4910-14-M

Notices

Federal Register
Vol. 44, No. 142
Monday, July 23, 1979

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

ACTION

Charter of the Peace Corps Advisory Council

Pursuant to Executive Order 12137 and Section 9(c) of the Federal Advisory Committee Act, the following articles represent the CHARTER of the Peace Corps Advisory Council.

I. Designation

The committee's official designation is "The Peace Corps Advisory Council" (hereinafter referred to as the "Council").

II. Objectives

The objectives of the Council are to advise the President and the Director of the Peace Corps on initiatives needed to promote the purposes of the Peace Corps Act, and to assist in the implementation of such initiatives.

III. Duration

The Council will terminate on December 31, 1980, unless extended.

IV. Membership

The President shall appoint not more than 30 individuals to serve on the Council and shall designate one member as Chairperson. Members shall serve at the pleasure of the President.

V. Reporting and Support

The Council shall report to the Director of the Peace Corps. In addition, the Council shall submit annually to the President, through the Director of the Peace Corps, a report on its recommendations and activities.

The Peace Corps shall be responsible for providing necessary support for the Council.

VI. Duties

The duties of the Council are to provide guidance and advice on the implementation of initiatives needed to achieve the purposes of the Peace Corps—namely, to promote world peace and friendship by (1) helping people of other countries and areas in meeting their needs for trained manpower, (2) promoting a better understanding of the American people on the part of the peoples served, and (3) promoting a better understanding of other peoples on the part of the American people.

VII. Meetings

The Council shall meet at least two (2) times each calendar year.

VIII. Cost

The estimated annual costs for the Council are $80,000.00 and one-half (½) work year. Members of the Council shall receive no compensation for service on the Council. Each member may receive travel expenses, including per diem in lieu of subsistence.

This charter is filed on July 18, 1979.

Richard F. Celeste,

Peace Corps Director.

[FR Doc. 79-22692 Filed 7-20-79; 8:45 am]

BILLING CODE 6050-01-M

CIVIL AERONAUTICS BOARD

[Docket No. 35507]

Fitness Investigation of Fleming International Airways; Hearing

Notice is hereby given, pursuant to the provisions of the Federal Aviation Act of 1958, as amended, that a hearing in the above-entitled proceeding is assigned to be held on August 14, 1979, at 10:00 a.m. (local time), in Room 1003, Hearing Room B, Universal North Building, 1875 Connecticut Avenue, N.W., Washington, D.C., before the undersigned.

For information concerning the issues involved and other details in this proceeding, interested persons are referred to the prehearing conference report dated July 16, 1979, and other documents which are in the docket of this proceeding on file in the Docket Section of the Civil Aeronautics Board.

Dated at Washington, D.C., July 17, 1979.

Richard M. Hartsock,

Administrative Law Judge.

[FR Doc. 79-22693 Filed 7-20-79; 8:45 am]

BILLING CODE 6320-01-M

COMMISSION ON CIVIL RIGHTS

California Advisory Committee; Agenda and Notice of Open Meeting

Notice is hereby given, pursuant to the provisions of the rules and regulations of the U.S. Commission on Civil Rights, that a planning meeting of the California Advisory Committee (SAC) of the Commission will convene at 11 a.m. and will end at 1 p.m. on August 10, 1979, at the Western Regional Office, 312 North Spring Street, Room 1015, Los Angeles, California 90012.

Persons wishing to attend this open meeting should contact the Committee Chairperson, or the Western Regional Office of the Commission, 312 North Spring Street, Room 1015, Los Angeles, California 90012.

The purpose of this meeting is for the Subcommittee to discuss minority economic development issues in the State of California.

This meeting will be conducted pursuant to the provisions of the rules and regulations of the Commission.

Dated at Washington, D.C., July 18, 1979.

John I. Binkley,

Advisory Committee Management Officer.

[FR Doc. 79-22663 Filed 7-20-79; 8:45 am]—

BILLING CODE 6335-01-M

Hawaii Advisory Committee; Agenda and Notice of Open Meeting

Notice is hereby given, pursuant to the provisions of the rules and regulations of the U.S. Commission on Civil Rights, that a planning meeting of the Hawaii Advisory Committee (SAC) of the Commission will convene at 2 pm and will end at 5 pm on August 18, 1979, at the Ala Moana Hotel, 410 Atkinson Drive, Honolulu, Hawaii 96814.

Persons wishing to attend this open meeting should contact the Committee Chairperson, or the Western Regional Office of the Commission, 312 North Spring Street, Room 1015, Los Angeles, California 90012.

The purpose of this meeting is to plan for the Hawaii State Advisory Committee project on equal opportunities for Native Hawaiians.

This meeting will be conducted pursuant to the provisions of the rules and regulations of the Commission.

Dated at Washington, D.C., July 18, 1979.

John I. Binkley,

Advisory Committee Management Officer.

[FR Doc. 79-22669 Filed 7-20-79; 8:45 am]

BILLING CODE 6335-01-M

DEPARTMENT OF COMMERCE

Bureau of the Census

Annual Surveys in Manufacturing Area; Consideration

Notice is hereby given that the Bureau of the Census is considering a proposal to initiate or to continue the annual surveys listed below for the year 1979 and for each year thereafter under the authority of title 13, United States Code, sections 182, 224, and 225. These surveys, most of which have been conducted for many years, are significant in the manufacturing area. On the basis of information and recommendations received by the Bureau of the Census, the data have significant application to the needs of the public and industry and are not available from nongovernmental or other governmental sources.

The establishments covered by these surveys directly account for the bulk of all manufacturing employment. The information to be developed from these surveys is necessary for an adequate measurement of total industrial production. Government agencies need data on the output of these industries. Manufacturers in the industries involved, as well as their suppliers and customers and the general public, have all requested such data in the interest of business efficiency and stability.

These surveys, if conducted, shall begin not earlier than August 20, 1979.

Most of the following commodity or product surveys provide data on shipments and/or production; some provide data on stocks, unfilled orders, orders booked, consumption, etc. Reports will be required of all or a sample of establishments engaged in the production of the items covered by the following list of surveys. These surveys have been arranged under major group headings based on the Standard Industrial Classification Manual (1972 edition) promulgated by the Office of Management and Budget for the use of Federal statistical agencies.

Major Group 22—Textile Mill Products

Broadwoven goods finished
Narrow fabrics
Yarn production

Major Group 23—Apparel and Other Finished Products Made From Fabrics and Similar Materials

Apparel
Brassieres, corsets, and allied garments
Gloves and mittens

Major Group 24—Lumber and Wood Products, Except Furniture

Hardwood plywood
Softwood plywood
Lumber

Major Group 26—Paper and Allied Products

Pulp, and detailed grades of paper and board

Major Group 28—Chemicals and Allied Products

Industrial gases
Inorganic chemicals
Pharmaceutical preparations, except biologicals
Sulfuric acid

Major Group 29—Petroleum Refining and Related Industries

Asphalt and tar roofing and siding products

Major Group 30—Rubber and Miscellaneous Plastics Products

Rubber
Plastics products

Major Group 31—Leather and Leather Products

Shoes and slippers (by method of construction)

Major Group 32—Stone, Clay, and Glass

Consumer, scientific, technical, and industrial glassware
Fibrous glass

Major Group 33—Primary Metal Industries

Steel mill products
Insulated wire and cable
Magnesium mill products

Major Group 34—Fabricated Metal Products Except Ordnance, Machinery, and Transportation Equipment

Commercial steel forgings
Steel power boilers
Selected heating equipment
Metal cans

Major Group 35—Machinery, Except Electrical

Internal combustion engines
Tractors, except garden tractors
Farm machines and equipment
Mining machinery and mineral processing equipment
Refrigeration and air-conditioning equipment, including warm air furnaces
Computers and office and accounting machines
Pumps and compressors
Selected industrial air pollution control equipment
Construction machinery
Anti-friction bearings

Major Group 36—Electrical Machinery, Equipment, and Supplies

Radios, televisions, and phonographs
Motors and generators
Wiring devices and supplies
Switchgear, switchboard apparatus, relays, and industrial controls
Selected electronic and associated products, including telephone and telegraph apparatus
Electric housewares and fans
Electric lighting fixtures
Major household appliances

Major Group 37—Transportation Equipment

Aircraft propellors

Major Group 38—Professional, Scientific, and Controlling Instruments; Photographic and Optical Goods; Watches and Clocks

Selected instruments and related products
Atomic energy products and services

The following survey represents an annual supplement of a monthly survey and will cover the same establishments canvassed monthly. There will be no duplication of reporting, however, since the type of data collected on the annual supplement will be different from that collected monthly.

Major Group 32—Stone, Clay, and Glass

Glass containers

The following list of surveys represents annual counterparts of monthly and quarterly surveys and will cover only those establishments which are not canvassed or do not report in the more frequent surveys. Accordingly, there will be no duplication in reporting. The content of these annual reports will be identical with that of the monthly and quarterly reports.

Major Group 20—Food and Kindred Products

Flour milling products

Major Group 22—Textile Mill Products

Finishing plant report—broadwoven fabrics
Consumption of wool and other fibers, and production of tops and noils
Carpet and rugs
Knit fabric production

Major Group 23—Apparel and Other Finished Products Made From Fabrics and Similar Materials

Sheets, pillowcases, and towels

Major Group 25—Furniture and Fixtures

Mattresses and bedsprings

Major Group 26—Paper and Allied Products

Converted flexible packaging products

Major Group 28—Chemicals and Allied Products

Phosphatic fertilizer materials
Paint, varnish, and lacquer

Major Group 30—Rubber and Miscellaneous Products

Plastics bottles

Major Group 32—Stone, Clay, and Glass

Glass containers
Refractories

Clay construction products

Major Group 33—Primary Metal Industries

Nonferrous castings
Iron and steel foundries
Steel inventories (Consumers and Producers Reports)
Copper inventories

Major Group 34—Fabricated Metal Products Except Ordnance, Machinery, and Transportation Equipment

Plumbing fixtures
Steel shipping drums and pails
Closures for containers

Major Group 35—Machinery, Except Electrical

Construction machinery

Major Group 36—Electrical Machinery, Equipment and Supplies

Fluorescent lamp ballasts

Major Group 37—Transportation Equipment

Aircraft engines
Complete aircraft
Backlog of orders for aircraft, space vehicles, missiles, engines, and selected parts
Truck trailers

The annual survey of manufactures will collect general statistical data such as employment, payroll, workhours, capital expenditures, cost of materials consumed, gross book value, retirements, and depreciation of fixed assets, rental payments, supplemental labor costs, information on the quantity of fuels used, etc. This survey, while conducted on a sample basis, will cover all manufacturing industries, including data on plants under construction but not yet in operation.

A survey of research and development (R&D) activities will be conducted. The major data to be obtained in this survey will include total R&D expenditures by source of funds, the number of scientists and engineers employed, the amounts spent for pollution abatement and energy R&D, and, for comparative purposes, the total net sales and receipts and the total employment of the company.

A survey of shipments to Federal Government agencies is planned to provide information on the impact of Federal procurement on selected industries and on the economy of States, standard metropolitan statistical areas, and geographic regions.

The annual survey of oil and gas will canvass the industry which provides most of the fuel produced in the United States as well as a substantial portion of the hydrocarbon raw material requirements of many industries. The survey will collect information on exploration, development, and production costs; sales volumes and values; drilling activity; and assets in the crude petroleum and natural gas industry.

The annual survey on pollution abatement expenditures is designed to collect from the manufacturing area total expenditures by industry to abate pollutant emissions. The survey covers current operating costs and capital expenditures by industry to reduce pollution in its air, water, or solid forms. It will also obtain the costs recovered from abatement activities and quantities of pollutants abated.

The survey of plant capacity will obtain information such as number of shifts; the actual operating rate; the number of production workers for actual, preferred, and practical operating rates; the reasons for operating at less than capacity; and the length of time required to reach and maintain practical rates. The survey will be done on a sample basis and will cover all manufacturing industries.

Copies of the proposed forms will be made available on request to the Director, Bureau of the Census, Washington, D.C. 20233.

Any suggestions or recommendations concerning the subject matter of these proposed surveys should be submitted in writing to the Director of the Bureau of the Census on or before September 20, 1979 in order to receive consideration.

Dated: July 17, 1979.

Daniel B. Levine,

Acting Director, Bureau of the Census.

[FR Doc. 79-22077 Filed 7-20-79; 8:45 am]

BILLING CODE 3510-07-M

Economic Development Administration

Petitions by Fourteen Producing Firms for Determinations of Eligibility To Apply for Trade Adjustment Assistance

Petitions have been accepted for filing from fourteen firms: (1) Ginsburg Manufacturing Company, Inc., 583 Broadway, New York, New York 10012, a producer of women's lingerie and robes (accepted July 5, 1979); (2) I. S. Sutton & Sons, Inc., 200 Fifth Avenue, New York, New York 10010, a producer of stuffed toys and dolls (accepted July 5, 1979); (3) Progress Knitwear Corporation, 250 44th Street, Brooklyn, New York 11232, a producer of men's sweaters and sportshirts and women's tops (accepted July 5, 1979); (4) Little World, Inc., 112 West 34th Street, New York, New York 10001, a producer of children's dresses, coats, suits, pants and sportswear (accepted July 9, 1979); (5) Schooner Knitwear Corporation, 412 Broadway, New York, New York 10013, a producer of women's sweaters, tops, shirts and blouses (accepted July 10, 1979); (6) Hornell Garments, Inc., 432 12th Street, Brooklyn, New York 11215, a producer of women's raincoats (accepted July 11, 1979); (7) Jewel Trend Button Corporation, 575 Eighth Avenue, New York, New York 10018, a producer of buttons, buckles and novelty jewelry (accepted July 11, 1979); (8) Zimco Industries, Inc., 390 Fifth Avenue, New York, New York 10018, a producer of men's and boys' suits and coats (accepted July 11, 1979); (9) S. G. Taylor Chain Company, Inc., 3 141st Street, Hammond, Indiana 46325, a producer of metal chain (accepted July 11, 1979); (10) Cavalier Clothes, Inc., 90-09 Van Wyck Expressway, Jamaica, New York 11435, a producer of men's and women's coats and vests (accepted July 11, 1979); (11) Ware Knitters, Inc., East Main Street, Ware, Massachusetts 01082, a producer of knit fabrics; and men's and women's sport shirts (accepted July 12, 1979); (12) Keystone Camera Corporation, 468 Getty Avenue, Clifton, New Jersey 07015, a producer of cameras, projectors and accessories (accepted July 12, 1979); (13) Sally Gee, Inc., 395 Broad Avenue, Ridgefield, New Jersey 07657, a producer of women's sweaters, tops and pants (accepted July 13, 1979); and (14) Victor Wraps Inc., Broadway & Jefferson Streets, Camden, New Jersey 08104, a producer of women's suits and coats (accepted July 13, 1979).

The petitions were submitted pursuant to Section 251 of the Trade Act of 1974 (Public Law 93-618) and § 315.23 of the Adjustment Assistance Regulations for Firms and Communities (13 CFR Part 315).

Consequently, the United States Department of Commerce has initiated separate investigations to determine whether increased imports into the United States of articles like or directly competitive with those produced by each firm contributed importantly to total or partial separation of the firm's workers, or threat thereof, and to a decrease in sales or production of each petitioning firm.

Any party having a substantial interest in the proceedings may request a public hearing on the matter. A request for a hearing must be received by the Chief, Trade Act Certification Division, Economic Development Administration, U.S. Department of Commerce, Washington, D.C. 20230, no later than the close of business of the tenth calendar day following the publication of this notice.

Jack W. Osburn, Jr.,

Chief, Trade Act Certification Division, Office of Eligibility and Industry Studies.

[FR Doc. 79-22694 Filed 7-20-79; 8:45 am]

BILLING CODE 3510-24-M

Industry and Trade Administration

[Dept. Organization Order 41-1; D.O.O. Reference 10-3, 40-1]

Office of the Assistant Secretary for Industry and Trade; Statement of Organization, Function, and Delegation of Authority

Effective Date: June 21, 1979.

Section 1. Purpose

This order delegates authority to the Senior Deputy Assistant Secretary for Industry and Trade and prescribes the organization and assignment of functions within the Office of the Assistant Secretary for Industry and Trade.

Section 2. Delegations of Authority.

.01 Pursuant to Department Organization Order 10-3 of December 4, 1977, as amended, the following authorities delegated to the Assistant Secretary for Industry and Trade by the Secretary of Commerce are hereby delegated to the Senior Deputy Assistant Secretary for Industry and Trade.

a. The Defense Production Act of 1950, as amended, (50 U.S.C. App. 2061 et seq.) conferred on the Secretary under: (1) Executive Order 10480, dated August 14, 1953, as amended, including authority to issue or modify orders restricting surface transportation and discharge of certain commodities or for the prohibition of movement of American carriers to certain designated destinations, which authority has heretofore been implemented by the issuance of Transportation Order T-1 and T-2, except the authority to create new agencies within the Department of Commerce; and (2) Executive Order 11912, dated April 13, 1976;

b. Executive order 11490 of October 28, 1969, as amended, as it relates to the development of national emergency preparedness plans and programs concerning production functions and to the regulations and control of exports and imports under the jurisdiction of the economic stabilization objectives;

c. Section 1441 of the Public Health Service Act, as amended by the Safe Drinking Water Act (42 U.S.C. 300j) conferred on the Secretary under Executive Order 11879 of September 17, 1975, involving materials allocation of chemicals or substances necessary for treatment of water;

d. The National Security Act of 1947 (50 U.S.C. 401 et seq.) as amended, as it relates to mobilization preparedness responsibilities assigned thereunder;

e. The Strategic and Critical Materials Stockpiling Act, (50 U.S.C. 98-98h), as amended, with respect to the quality and quantity of materials acquired for the national stockpile and disposal of materials determined to be in excess of national defense requirements;

f. Executive Order 11179 of September 22, 1964, as amended by Executive Order 11725 of June 27, 1973, with respect to the establishment and training of the National Defense Executive Reserve;

g. Executive Order 10421 of December 31, 1952, providing for the physical security of facility important to the national defense;

.02 For the purpose of the authorities delegated in Section 2.01 above, the Deputy Assistant Secretary for Trade Regulation shall report to the Senior Deputy Assistant Secretary for Industry and Trade and shall serve as his deputy and act in his absence.

.03 The Senior Deputy Assistant Secretary for Industry and Trade may redelegate his authority subject to such conditions in exercise of such authority as he may prescribe.

Section 3. Office of the Assistant Secretary for Industry and Trade

.01 The *Office of the Assistant Secretary for Industry and Trade* shall consist of the following:

Senior Deputy Assistant Secretary for Industry and Trade The Executive Staff

.02 The *Senior Deputy Assistant Secretary for Industry and Trade* shall perform such duties as the Assistant Secretary shall assign; shall carry out the Assistant Secretary's responsibilities in connection with the Defense Production Act of 1950, as amended; shall chair the Short Supply Monitoring Committee; and shall assume the duties of the Assistant Secretary during the latter's absence or disability or in the event of a vacancy in the office.

.03 The *Executive Staff* shall provide management and control of the operations of the Office of the Assistant Secretary, coordinate and follow-up on action items assigned by the Assistant Secretary to ITA elements, and coordinate or handle special projects of the Assistant Secretary.

Section 4. Administrative, Public Affairs, and Field Support

.01 Management, budget, personnel, travel and administrative services, and public affairs and information services for the Office of the Assistant Secretary for Industry and Trade shall be provided by the administrative offices of the Industry and Trade Administration.

.02 Field support will be provided by the Bureau of Field Operations.

Frank A. Weil,

Assistant Secretary for Industry and Trade.

[FR Doc. 79-22078 Filed 7-20-79; 8:45 am]

BILLING CODE 3510-25-M

National Oceanic and Atmospheric Administration

Approval of the Virgin Islands Coastal Zone Management Program

Pursuant to the authority contained in Section 306(a) of the Coastal Zone Management Act of 1972, as amended (16 U.S.C. 1445(a)), notice is hereby given that the Assistant Administrator for Coastal Zone Management (on behalf of the Secretary of Commerce) on June 8, 1979, approved the coastal program of the Virgin Islands.

Approval activates Federal agency responsibility for being consistent with this program pursuant to the Federal consistency provisions of the Coastal Zone Management Act as of the date of approval. Further information on the responsibilities of affected Federal agencies in this regard may be found in 15 CFR Part 930, published in the Federal Register, at page 10510, on March 13, 1978.

A copy of the findings made by the Assistant Administrator in determining that the program meets the requirements of the Coastal Zone Management Act may be obtained upon request from the Office of Coastal Zone Management. Inquires regarding the Virgin Islands program should be addressed to: Ann H. Berger-Blundon, Assistant Regional Manager, for the Gulf and Islands, Office of Coastal Zone Management, Page Building I, 3300 Whitehaven St. NW., Washington, D.C. 20235; 202/254-7546.

M. P. Snidero,

Assistant Administrator for Administration.

July 16, 1979.

[FR Doc. 79-22584 Filed 7-20-79; 8:45 am]

BILLING CODE 3510-22-M

Preliminary Approval of the Mississippi and Louisiana Coastal Management Programs

Pursuant to the authority contained in Section 305(d) of the Coastal Zone Management Act of 1972, as amended (16 U.S.C. 1445(a)), notice is hereby given that the Assistant Administrator for Coastal Zone Management (on behalf of the Secretary of Commerce) gave on June 8, 1979, preliminary approval to coastal programs of Mississippi and Louisiana.

A copy of the findings made by the Assistant Administrator in determining that the programs meet the requirements of the Coastal Zone Management Act may be obtained upon request from the Office of Coastal Zone Management. Inquiries regarding the Mississippi Program should be addressed to: Ann H. Berger-Blundon, Assistant Regional Manager, for the Gulf and Islands, Office of Coastal Zone Management, Page Building I, 3300 Whitehaven St., NW., Washington, D.C. 20235, 202/254-7546.

Inquiries regarding the Louisiana Program should be addressed to: William C. Millhouser, Program Assistant for the Gulf and Islands, Office of Coastal Zone Management, Page Building I, 3300 Whitehaven St., NW., Washington, D.C. 20235, 202/254-7546.

M. P. Snidero,

Assistant Administrator for Administration.

July 16, 1979.

[FR Doc. 79-22586 Filed 7-20-79; 8:45 am]

BILLING CODE 3510-22-M

Gulf of Mexico Fishery Management Council; Public Meeting

AGENCY: National Marine Fisheries Service, NOAA.

SUMMARY: The Gulf of Mexico Fishery Management Council, established by Section 302 of the Fishery Conservation and Management Act of 1976 (Public Law 94-265), will meet to: (1) review status reports on development of fishery management plans; (2) consider foreign fishing applications, if any, and (3) conduct other business.

DATES: The meeting will convene on Tuesday, August 7, 1979, at 1:30 p.m.; Wednesday, and Thursday, August 8 & 9, 1979, at 8:30 a.m.; adjourning on August 7 & 8, 1979, at 5 p.m. and on August 9, 1979, at approximately 12 noon. The meeting is open to the public.

ADDRESS: The meeting will take place in the Regency Room of the Sheraton Marina Inn, 300 North Shoreline, Corpus Christi, Texas.

FOR FURTHER INFORMATION CONTACT: Gulf of Mexico Fishery Management Council, Lincoln Center, Suite 881, 5401 West Kennedy Boulevard, Tampa, Florida 33609, Telephone: (813) 228-2815.

Dated: July 18, 1979.

Winfred H. Meibohm,

Executive Director, National Marine Fisheries Service.

[FR Doc. 79-22712 Filed 7-20-79; 8:45 am]

BILLING CODE 3510-22-M

North Pacific Fishery Management Council, Scientific and Statistical Committee, and Advisory Panel; Cancellation of Public Meeting

AGENCY: National Marine Fisheries Service, NOAA.

SUMMARY: Notice is hereby given that the scheduled Council meeting on July 25, 26, & 27, 1979, of the North Pacific Fishery Management Council as published in the Federal Register, Vol. 44, No. 136, page 40913, Friday, July 13, 1979, has been cancelled.

Dated: July 17, 1979.

Winfred H. Meibohm,

Executive Director, National Marine Fisheries Service.

[FR Doc. 79-22713 Filed 7-20-79; 8:45 am]

BILLING CODE 3510-22-M

Pacific Fishery Management Council's Billfish Subpanel; Cancellation of Public Meeting

AGENCY: National Marine Fisheries Service, NOAA.

SUMMARY: Notice is hereby given that the scheduled meeting on July 20, 1979, of the Pacific Fishery Management Council, as published in the Federal Register, Vol. 44, No. 131, page 39572, Friday, July 6, 1979, has been cancelled.

Dated: July 18, 1979.

Winfred H. Meibohm,

Executive Director, National Marine Fisheries Service.

[FR Doc. 79-22711 Filed 7-20-79; 8:45 am]

BILLING CODE 3510-22-M

Yellowfin Tuna Fisheries; Notice of Closure

AGENCY: National Oceanic and Atmospheric Administration/ Commerce.

ACTION: Notice of Closure.

SUMMARY: This notice closes the unrestricted 1979 fishery for yellowfin tuna in the American Tropical Tuna Commission's Yellowfin Regulatory Area at 0001 hours, local time, July 21, 1979.

EFFECTIVE DATE: 0001 hours, local time, July 21, 1979.

FOR FURTHER INFORMATION CONTACT: Mr. Gerald V. Howard, Regional Director, Southwest Region, National Marine Fisheries Service, 300 S. Ferry Street, Room 2016, Terminal Island, California 90731, Telephone: (213) 548-2518.

SUPPLEMENTARY INFORMATION: Section 280.5 provides that the Assistant Administrator for Fisheries, National Oceanic and Atmospheric Administration shall announce the closure date for the yellowfin tuna fisheries in the Federal Register.

Notice is hereby given that the Assistant Administrator will close the 1979 season for taking yellowfin tuna without restriction by persons and vessels subject to the jurisdiction of the United States at 0001 hours, local time, on July 21, 1979. Actual notice of this closure will be given to vessel owners and/or managing owners participating in this fishery.

(16 U.S.C. 1801 *et seq.*)

Signed at Washington, D.C., this 17th day of July, 1979.

Winfred H. Meibohm,

Executive Director, National Marine Fisheries Service.

[FR Doc. 79-22608 Filed 7-20-79; 8:45 am]

BILLING CODE 3510-22-M

National Technical Information Service

Government-Owned Inventions; Availability for Licensing

The inventions listed below are owned by the U.S. Government and are available for domestic and possibly foreign licensing in accordance with the licensing policies of the agency-sponsors.

Copies of the patents cited are available from the Commissioner of Patents & Trademarks, Washington, DC 20231, for $.50 each. Requests for copies of patents must include the patent number.

Copies of the patent applications can be purchased from the National Technical Information Service (NTIS), Springfield, Virginia 22161 for $4.00 ($8.00 outside North American Continent). Requests for copies of patent applications must include the PAT-APPL number. Claims are deleted from patent application copies sold to the public to avoid premature disclosure in the event of an interference before the Patent and Trademark Office. Claims and other technical data will usually be made available to serious prospective licensees by the agency which filed the case.

Requests for licensing information on a particular invention should be directed to the address cited for the agency-sponsor.

Douglas J. Campion,

Patent Program Coordinator, National Technical Information Service.

U.S Department of Health, Education and Welfare, National Institutes of Health, Chief, Patent Branch, Westwood Building, Bethesda, Md. 20250.

Patent application 749,093: Undercapeptide and Tumour Assay; filed December 9, 1976.

U.S. Department of the Interior, Branch of Patents, 18th and C Streets, N.W., Washington, DC 20240.

Patent 4,107,266: Production of Pura Alumina from Iron Contaminated Sulfate Liquors; filed July 22, 1977, patented August 15, 1978. Not available NTIS.

U.S. Department of the Air Force, AF/JACP, 1900 Half Street, S.W., Washington, DC 20324.

Patent 4,115,390: Method for the Preparation of 1-Alkyl Pyridinium Chlorides; filed August 19, 1977; patented September 19, 1978; not available NTIS.

Patent 4,117,207: Molybdenum Chloride-Tetrachloroaluminate Thermal Battery; filed October 14, 1977; patented September 26, 1978; not available NTIS.

Patent 4,131,461: Method and Apparatus for Use in the Extrusion of Billets; filed June 21, 1977; patented December 26, 1978; not available NTIS.

Patent 4,131,625: 4,4 feet Bis(3-Ethynylphenoxy)Diphenylsulfone; filed January 19, 1978; patented December 26, 1978; not available NTIS.

Patent 4,131,748: p-Terphenylene-Dicarboxylic Acids and Their Synthesis; filed June 29, 1977; patented December 26, 1978; not available NTIS.

Patent 4,131,792: Fabry-Perot Diplexer; filed January 24, 1978; patented December 26, 1978; not available NTIS.

Patent 4,131,852: Single Dispersive Delay Line compressive Receiver; filed September 28, 1977; patented December 26, 1978; not available NTIS.

Patent 4,132,660: Grease Compositions; filed March 1, 1978; patented January 2, 1979; not available NTIS.

Patent 4,135,548: Liquid Nitrogen Level Controller; filed August 11, 1977; patented January 23, 1979; not available NTIS.

Patent 4,136,234: Charge Sensing Electrode for a Primary Battery; filed April 17, 1978; patented January 23, 1979; not available NTIS.

Patent 4,137,370: Titanium and Titanium Alloys Ion Plated with Noble Metals and Their Alloys; filed August 16, 1977; patented January 30, 1979; not available NTIS.

Patent 4,137,374: Method for State of charge of Primary Battery; filed May 2, 1978; patented January 30, 1979; not available NTIS.

U.S. Department of Agriculture, Research Agreements and Patent Branch, General Service Division, Federal Bldg., Agricultural Research Service, Hyattsville, Md. 20782.

Patent application 945,976: Inhibition of Lysinoalanine Formation by Lysine Acylation; filed September 26, 1978.

Patent application 4,134,863: Highly Absorbent Graft Copolymers of Polyhydroxy Polymers, Acrylonitrile, and Acrylic Comonomers; filed December 6, 1976; patented January 16, 1979; not available NTIS.

Patent application 4,136,131: Extraction of Rubber of Rubberlike Substances; from Fibrous Plant Materials; filed March 31, 1978; patented January 23, 1979; not available NTIS.

Patent application 4,136,509: Apparatus for Harvesting Vegetable heads; filed April 20, 1977; patented January 30, 1979; not available NTIS.

U.S. Department of Energy, Assistant General Counsel for Patents, Washington, DC 20545.

Patent application 822,971: Megnetohydrodynamic Generator Electrode; filed August 8, 1977.

Patent application 825,518: Distributed Electrical Leads for Thermionic Converter; filed August 17, 1977.

Patent application 847,996: Method for Producing Hydrocarbon Fuels from Heavy Polynuclear Hydrocarbons by Use of Molten Metal Halide Catalyst; filed November 2, 1977.

Patent application 850,335: Method for Recovering Amorphous Silica from Geothermal Solutions; filed November 10, 1977.

Patent application 4,088,561: Apparatus for Electrophoresis Separation; filed June 27, 1977; patented May 9, 1978; not available NTIS.

Patent application 4,089,809: Regenerable Sorbent and Method for Removing Hydrogen Sulfide from Hot Gaseous Mixtures; filed March 1, 1976; patented May 16, 1978; not available NTIS.

U.S. Department of the Interior, Branch of Patents, 18th and C Streets, N.W., Washington, DC 20240.

Patent application 958,578: Extensible Brattice and Cantilevered Roof Mounted Support System Therefore; filed November 7, 1978.

Patent application 958,594: Link-Loc Chainless Haulage System; filed November 7, 1978.

Patent application 968,046: Automated Feed and Rotational Speed Control System of a Hydraulic Motor Operated Drill; filed December 8, 1978.

Patent 3,980,081: Self-Rescue Breathing Apparatus; filed June 25, 1975; patented September 14, 1976; not available NTIS.

Patent 4,090,399: Load Measuring Gage; filed July 31, 1974; patented May 23, 1976; not available NTIS.

Patent 4,090,736: Detachable Cab Construction for Mining Machines; filed February 24, 1977; patented May 23, 1978; not available NTIS.

Patent 4,098,956: Spectrally Selective Solar Absorbers; filed August 11, 1976; patented July 4, 1978; not available NTIS.

Patent 4,100,068: System for the Dielectrophoretic Separation of Particulate and Granular Material; filed January 13, 1977; patented July 11, 1978; not available NTIS.

Patent 4,110,107: Process for Reducing Molten Furnace Slags by Carbon Injection; filed November 7, 1977; patented August 29, 1978; not available NTIS.

Patent 4,113,314: Well Perforating Method for Solution Well Mining; filed June 24, 1977; patented September 12, 1978; not available NTIS.

Patent 4,128,133: Torquer/Thruster for Flexible Roofdrill; filed May 7, 1976; patented December 5, 1978; not available NTIS.

U.S. Department of the Navy, Assistant Chief for Patents, Office of Naval Research, Code 302, Arlington, Va. 22217.

Patent application 6,003,696: Device for Producing Extended Elongated Plasmas for X-Ray Lasers; filed January 1, 1979.

Patent application 945,984: Modular Containerized Firefighting System with Remote Standoff Capability; filed September 27, 1978.

Patent application 965,811: Method of LED Manufacture; filed December 4, 1978.

Patent application 966,674: Method for the Production of Hexanitrostilbene (HNS); filed December 5, 1978.

Patent 4,124,408: Method of Removing Deposits on Refrigeration System Surfaces; filed June 2, 1977; patented November 7, 1978; not available NTIS.

Patent 4,128,301: Optical Waveguice Power Divider; filed March 29, 1977; patented December 5, 1978; not available NTIS.

Patent 4,131,392: Deployable Rotor; filed January 31, 1977; patented December 26, 1978; not availabe NTIS.

Tennessee Valley Authority, Division of Law, Muscle Shoals, Ala. 35660.

Patent 4,134,750: Granular Ammonium Phosphate Sulfate and Urea-Ammonium Phosphate Sulfate Using a Common Pipe-Cross Reactor; filed December 19, 1977; patented January 16, 1979; not available NTIS.

U.S. Department of the Interior, Branch of Patents, 18th and C Streets, N.W., Washington, D.C. 20240.

Patent 4,116,368: Clog-Free Inorganic Grout Emplacement Gun; filed December 16, 1976; patented September 26, 1978; not available NTIS.

Patent 4,121,154: Alternating Current Potential Measuring Device; filed December 10, 1976; patented October 17, 1978; not available NTIS.

National Aeronautics & Space Administration, Assistant Gen. Couns. for Pat. Matters, NASA Code GP-2, Washington, D.C. 20546.

Patent application 6,008,211: Double-Beam Optical Method and Apparatus for Measuring Thermal Diffusivity and Other Molecular Dynamic Processes in Utilizing

the Transient Thermal Lens Effect; filed January 31, 1979.
Patent application 6,008,212: Method of Mitigating Titanium Impurities Effects in p-Type Silicon Material for Solar Cells; filed January 31, 1979.
Patent application 969,757: A Method and Technique for Installing Light-Weight Fragile, High-Temperature Fiber Insulation; filed December 15, 1978.
Patent 4,133,697: Solar Array Strip and a Method for Forming the Same; filed June 24, 1977; patented January 9, 1979; not available NTIS.
Patent 4,133,941: Formulated Plastic Separators for Soluble Electrode Cells; filed March 10, 1977; patented January 9, 1979; not available NTIS.
Patent 4,134,447: Thermal Compensator for Closed-Cycle Helium Refrigerator; filed September 30, 1977; patented January 16, 1979; not available NTIS.
Patent 4,134,744: Fine Particulate Capture Device; filed November 8, 1978; patented January 16, 1979; not available NTIS.
Patent 4,134,786: Process for Purification of Waste Water Produced by a Kraft Process Pulp and Paper Mill; filed December 15, 1976; patented January 16, 1979; not available NTIS.

U.S. Department of the Interior, Branch of Patents, 18th and C Streets, N.W., Washington, D.C. 20240.

Patent application 950,761: Backwashing Reverse-Osmosis and Ultrafiltration Membrane; filed October 12, 1978.
Patent application 950,762: Method of and Apparatus for Detecting Escaping Leach Solution; filed October 12, 1978.
Patent 4,079,592: Method of and Apparatus for Feeding and Inserting Bolts in a Mine Roof; filed March 4, 1977; patented March 21, 1978; not available NTIS.
Patent 4,079,809: Muffler for Pneumatic Drill; filed July 13, 1977; patented March 21, 1978; not available NTIS.
Patent 4,085,017: Recovery of Copper and Nickel from Alloys; filed September 6, 1977; patented April 18, 1978; not available NTIS.
Patent 4,133,967: Two-Stage Electric Arc-Electroslag Process and Apparatus for Continuous Steelmaking; filed June 24, 1977; patented January 9, 1979; not available NTIS.

[FR Doc. 79-22586 Filed 7-20-79; 8:45 am]
BILLING CODE 3510-04-M

COUNCIL ON ENVIRONMENTAL QUALITY

Second Progress Report on Agency Implementing Procedures Under the National Environmental Policy Act

July 18, 1979.

AGENCY: Council on Environmental Quality, Executive Office of the President.

ACTION: Information Only: Publication of Second Progress Report on Agency Implementing Procedures Under The National Environmental Policy Act.

SUMMARY: In response to President Carter's Executive Order 11991, on November 29, 1978, the Council on Environmental Quality issued regulations implementing the procedural provisions of the National Environmental Policy Act ("NEPA"). (43 FR 55978-56007; 40 CFR 1500-08) Section 1507.3 of the regulations provides that each agency of the Federal Government shall adopt procedures to supplement the regulations by July 30, 1979. The Council has indicated to Federal agencies its intention to publish progress reports on agency efforts to develop implementing procedures under the NEPA regulations. The purpose of these progress reports, the second of which appears below, is to provide an update on where agencies stand in this process and to inform interested persons of when to expect the publication of proposed procedures for their review and comment.

FOR FURTHER INFORMATION CONTACT: Nicholas C. Yost, General Counsel, Council on Environmental Quality, 722 Jackson Place, N.W., Washington, D.C. 20006; 202-395-5750.

Progress Report on Agency Implementing Procedures Under the National Environmental Policy Act.

At the direction of President Carter (Executive Order 11991), on November 29, 1978, the Council on Environmental Quality issued regulations implementing the procedural provisions of the National Environmental Policy Act ("NEPA"). These regulations appear at Volume 43 of the Federal Register, pages 55978-56007 and Volume 40 of the Code of Federal Regulations, Sections 1500-1508. Their purpose is to reduce paperwork and delay associated with the environmental review process and to foster environmental quality through better decisions under NEPA.

Section 1507.3 of the NEPA regulations provides that each agency of the Federal government shall adopt procedures to supplement the regulations. The purpose of agency "implementing procedures," as they are called, is to translate the broad standards of the Council's regulations into practical action in Federal planning and decisionmaking. Agency procedures will provide government personnel with additional, more specific direction for implementing the procedural provisions of NEPA, and will inform the public and State and local officials of how the NEPA regulations will be applied to individual Federal programs and activities.

In the course of developing implementing procedures, agencies are required to consult with the Council and to publish proposed procedures in the Federal Register for public review and comment. Proposed procedures must be revised as necessary to respond to the ideas and suggestions made during the comment period. Thereafter, agencies are required to submit the proposed final version of their procedures for 30 days review by the Council for conformity with the Act and the NEPA regulations. After making such changes as are indicated by the Council's review, agencies are required to promulgate their final procedures by July 30.

It is apparent that a number of Federal agencies will not meet this deadline. The Council has advised Federal agencies that failure to do so would represent a violation of § 1507.3 of the NEPA regulations. Substantial delays in adopting procedures beyond this deadline would also raise more general concerns about the adequacy of an angency's compliance with NEPA.

On May 7, 1979 the Council published its first progress report on agency implementing procedures, 44 Federal Register 26781-82. Its second progress report appears below. The Council hopes that concerned members of the public will review and comment upon agency procedures to insure that the reforms required by President Carter and by the Council's regulations are implemented. Agencies preparing implementing procedures are listed under one of the following three categories:

Category #1: Proposed Procedures Have Been Published

This category includes agencies whose proposed procedures have either appeared in the Federal Register or been transmitted to the Federal Register for publication.

Advisory Council on Historic Preservation, 44 FR 40653 (July 12)
Central Intelligence Agency, 44 FR 23103 (April 18)
Department of Agriculture, 44 FR 25606 (May 1)
- Animal and Plant Health Inspection Service, 44 FR 38945 (July 3)
- Forest Service, 44 FR 23891 (April 23)
- Rural Electrification Administration, 44 FR 28383 (May 15)
- Soil Conservation Service, 44 FR 25786 (May 2)

Department of Defense, 44 FR 28338 (May 15)
- Department of the Air Force, (At the Federal Register)
- Army Corps of Engineers, 44 FR 38292 (June 29)

Department of Energy, 44 FR 42136 (July 18)
Department of the Interior, 44 FR 40437 (July 10)
Department of Justice, (At the Federal Register)

Department of Transportation, 44 FR 31341 (May 31)
Coast Guard, 44 FR 37098 (June 25)
Federal Aviation Administration, 44 FR 32094 (June 4)
Federal Railroad Administration, 44 FR 40174 (July 9)
Department of the Treasury, 44 FR 39692 (July 6)
Environmental Protection Agency, 44 FR 35158 (June 18)
Export-Import Bank, 44 FR 28823 (May 17)
Federal Communications Commission, 44 FR 38913 (July 3)
Federal Maritime Commission, 44 FR 29122 (May 18)
Federal Trade Commission, (At the Federal Register)
General Services Administration,
Agency Wide Procedures, 44 FR 33485 (June 11)
Public Buildings, 44 FR 27473 (May 10)
Marine Mammal Commission (At the Federal Register)
National Aeronautics & Space Administration, 44 FR 27161 (May 9)
National Capital Planning Commission, 44 FR 33185 (June 8)
Postal Service, 44 FR 36991 (June 25)
Tennessee Valley Authority, 44 FR 39679 (July 6)

Category #2. Anticipate Publication of Proposed Procedures by July 30

This category includes agencies which have developed a draft of implementing procedures as a basis for consultation with the Council and are expected to publish proposed procedures in the Federal Register by July 30, 1979.

Department of Agriculture*
Soil Conservation Service
Department of Defense*
Department of the Navy
Department of Housing and Urban Development
Department of Health, Education and Welfare**
Food and Drug Administration
Department of the Interior*
Bureau of Mines
Bureau of Reclamation
Fish and Wildlife Service
Geological Survey
Heritage Conservation and Recreation Service
National Park Sevice
Office of Surface Mining Control and Reclamation
Department of Labor
Department of Transportation*
Federal Highway Administration
Urban Mass Transportation Administration
Department of State
Federal Energy Regulatory Comission
National Science Foundation
Pennsylvania Avenue Development Corporation
Veterans Administration
Water Resources Council and River Basin Commissions

* Departmental Procedures Already Published.
** Departmental Procedures in Category #3.

Category #3: Publication of Proposed Procedures Delayed Beyond July 30.

This category includes agencies which are *not* expected to publish proposed procedures in the Federal Register by July 30, 1979.

Action

Civil Aeronautics Board
Community Services Administration
Consumer Product Safety Commission
Department of Agriculture*
Farmers Home Administration
Science and Education Administration
Department of Commerce
Economic Development Administration
National Oceanic and Atmospheric Administration
Department of Defense*
Department of the Army
Department of Health, Education and Welfare
Department of the Interior*
Bureau of Indian Affairs
Bureau of Land Management
Department of Transportation*
National Highway Traffic Safety Administration
Farm Credit Administration
Federal Deposit Insurance Corporation
Federal Home Loan Bank Board
Federal Reserve System
Interstate Commerce Commission
National Credit Union Administration
Nuclear Regulatory Commission
Securities and Exchange Commission
Small Business Administration
Smithsonian Institution

The development of agency implementing procedures is a critical stage in Federal efforts to reform the NEPA process. These procedures must, of course, be consistent with the Council's regulations and provide the means for reducing paperwork and delay and producing better decisions in agency planning and decisionmaking.

Interested persons will have the opportunity to make their suggestions for improving agency procedures when they are published in the Federal Register in proposed form. Broad public participation at this crucial juncture could go a long way toward ensuring that the goals of the NEPA regulations are widely implemented in the day-to-day activities of government.

Nicholas C. Yost,
General Counsel.

[FR Doc. 79-22750 Filed 7-20-79; 8:45 am]
BILLING CODE 3125-01-M

DEPARTMENT OF DEFENSE

Corps of Engineers, Department of the Army

Intent To Prepare a Draft Environmental Impact Statement (DEIS) for the Maalaea Small Boat Harbor Project, Maalaea, Maui

July 11, 1979.

AGENCY: U.S. Army Corps of Engineers, DoD, Honolulu District.

ACTION: Notice of Intent to Prepare a DEIS.

SUMMARY: 1. *Brief Description of the Proposed Action.* The proposed action is a harbor improvement project, the major objectives of which are to reduce surge within the harbor, reduce the navigational hazard in the entrance channel and provide for additional berthing spaces.

2. *Brief Description of the Reasonable Alternatives.* Preliminary alternative plans are based on input from the public as well as oceanographic information obtained from computer wave refraction analysis, theoretical wave diffraction analysis, aerial photographs, an underwater reconnaissance investigation and an examination of offshore subsurface borings. The authorized plan and four preliminary alternative plans all include realignment of the entrance channel. The authorized plan and one alternative plan propose extension of the existing south breakwater. Another alternative proposes construction of an offshore breakwater, and the fourth alternative includes construction of a new breakwater approximately 250 feet seaward (south) of the existing south breakwater which would substantially increase berthing space in the harbor.

3. *Brief Description of the Corps Scoping Process Which is Reasonably Foreseeable for the DEIS.*

a. Proposed Public Involvement Program. The program will involve coordination with the sponsoring agencies, other governmental agencies, community organizations, and the general public. Activities include informal meetings, workshops, formal public meetings, issuance of public notices and letter responses. All pertinent agencies have been notified of study initiation. An initial public meeting was held with interested agencies and the public in January 1979 and two workshops have been conducted subsequently in April and June of 1979.

b. Identification of Significant Environmental Issues to be Analyzed in Depth in the DEIS.

(1) Effect of alternatives on known and unknown archaeological and historic sites.

(2) Effect of the project on marine flora and fauna including the endangered humpback whale.

(3) Effect of the project on adjacent surfing sites.

(4) Assessment of the Maalaea community responses to alternatives.

c. Possible Assignments for Input into the EIS under Consideration among the Lead and Cooperating Agencies.

(1) *National Marine Fisheries Service:* Assessment of the effects of the project on the humpback whale.

(2) *U.S. Fish and Wildlife Service:* Provision of a Fish and Wildlife Coordination Act Section 2(b) report.

(3) *State Historical Preservation Officer:* Identification and evaluation of previous cultural resource surveys.

(4) *State Department of Transportation:* Socio-economic data.

(5) *State Department of Health:* Water quality data and Section 404 certification.

d. Identification of Other Environmental Review and Consultation Requirements.

(1) "Protection of Historic and Cultural Properties," 36 CFR Part 800 (44 FR, January 30, 1979), pursuant to Section 106 of the National Historic Preservation Act of 1966.

(2) Section 404 (Clean Water Act of 1977).

(3) Coastal Zone Management Act of 1973.

4. *Scoping Meeting.* A scoping meeting will not be held on this project. Significant agencies involved in the planning process are already informed of the potential action. These agencies include the sponsoring agency, State of Hawaii Department of Transportation, State Historic Preservation Officer, U.S. Fish and Wildlife Service, and the National Marine Fisheries Service.

5. *DEIS Schedule.* Under the present schedule the DEIS will be made available to the public in April 1980.

ADDRESS: Questions about the proposed action and DEIS can be answered by: Mr. Gary Wible, Project Engineer, U.S. Army Engineer District, Honolulu, Building 230, Fort Shafter, Hawaii 96858. Telephone: (808) 438–2627/1907.

Dated: July 11, 1979.

Peter D. Stearns,

Colonel, Corps of Engineers, District Engineer.

[FR Doc. 79-22587 Filed 7-20-79; 8:45 am]

BILLING CODE 3710-NN-M

Intent To Prepare Draft Environmental Impact Statement For Proposed Weyerhaeuser Co. Export Facility, DuPont, Wash.

July 11, 1979.

AGENCY: U.S. Army Corps of Engineers, Seattle District.

ACTION: Notice of Intent to prepare a draft environmental impact statement (EIS) for the proposed Weyerhaeuser Company export facility on Puget Sound at DuPont, Washington.

SUMMARY: 1. *Proposed Action.* The Weyerhaeuser Company proposes to construct and operate an export facility at DuPont, Washington, to provide a central location for receiving products from company manufacturing and woods operations in western Washington, and to allow for the export of those forest products using oceangoing vessels. The proposed facility would include a pier, terminal area, rail access, and access roads. The pier requires a Department of the Army permit in accordance with section 10 of the River and Harbor Act of March 3, 1899. The export facility will occupy 250 acres of a 3,200-acre site owned by Weyerhaeuser Company. No dredging will be performed.

2. *Alternatives.* The options available to the Corps of Engineers include: (a) Issue the permit, (b) issue the permit with special conditions, and (c) deny the permit. Alternatives to the proposed work to be studied by the applicant include: (a) No action, (b) development of an export facility at an alternative location, and (c) use of alternate pier and terminal designs and locations of upland facilities.

Twenty-eight candidate sites that could meet Weyerhaeuser Company criteria for an export site will be analyzed. Sites satisfying specific criteria relative to access, acreage, utilities, availability for purchase, and location will be selected for more detailed evaluation. Six design alternatives for pier, terminal, and terminal-pier access design at DuPont will be compared. These alternative designs were recommended by competing consultants, each of whom developed and analyzed several conceptual designs for these facilities. Additional pier access designs developed by Weyerhaeuser Company will be analyzed. The preferred action will be compared to the various design alternatives.

Various alternative sites at DuPont, identified as possible locations for the industrial facilities, will be examined. Environmental impacts of developing these sites will be evaluated.

3. *Corps of Engineers Scoping Process.*

a. *Public Involvement.* The draft EIS will receive broad public review. Copies will be provided appropriate Federal, state, and local agencies, affected Indian tribes, and other interested private organizations and parties for their review and comment. A public hearing will be held prior to publication of the final EIS. The final EIS Will also be distributed to interested parties for their review and comment.

b. *Significant Issues.* Significant issues to be analyzed in depth include: (1) Anticipated project impacts on the adjacent, environmentally sensitive Nisqually Delta, considered unique and regionally significant; (2) the Weyerhaeuser Company's intentions for future use of the project site, including potential mitigation plans, particularly as related to the Nisqually Delta; (3) the potential impacts of the proposed facility on listed and/or proposed endangered and threatened species, and/or their critical habitat, that may occur in the vicinity of the proposed project site (as per section 7 of the Endangered Species Act, as amended); (4) the nature and volume of forest products that would be diverted to the export facility from alternate regional facilities; (5) the elimination of 169 acres of vegetation and associated wildlife; (6) aesthetic impacts, including shoreline alteration and night noise levels; (7) water quality impacts as a result of ship exhaust, runoff from the pier access road, and increased risks of oil spills due to increased freighter traffic; and (8) project compliance with the Coastal Zone Management Act and the Pierce County Shoreline Master Program.

4. *Scoping Meeting.* A scoping meeting, as described in the Council on Environmental Quality regulations for implementing the procedural provisions of the National Environmental Policy Act of 1969 (NEPA), will not be held.

5. *DEIS Availability.* The draft EIS is presently scheduled to become available to the public on July 30, 1979.

6. *Address.* Information on the proposed action and the draft EIS can be obtained by contacting: Fred Weinmann or Steve Martin, Department of the Army, Seattle District, Post Office Box C–3755, Seattle, Washington 98124, ATTN: NPSEN-PL-ER, Phone: (206) 764–3625, (FTS 399–3625).

7. Dated July 1979.

Maxey B. Carpenter, Jr.,

Lt. Colonel, Corps of Engineers, Acting District Engineer.

[FR Doc. 79-22588 Filed 7-20-79; 8:45 am]

BILLING CODE 3710-ER-M

Department of the Navy

Chief of Naval Operations Executive Panel Advisory Committee Meeting

Pursuant to the provisions of the Federal Advisory Committee Act (5 U.S.C. App. I), notice is hereby given that the Chief of Naval Operations (CNO) Executive Panel Advisory Committee will meet on August 8-9, 1979, at the Pentagon, Washington, D.C. Sessions of the meeting will commence at 8:30 a.m. and terminate at 5:30 p.m. on both days. All sessions of the meeting will be closed to the public.

The entire agenda for the meeting will consist of discussions of strategic mobilization, intelligence briefings on major developments in Soviet naval forces, and review of future United States naval force plans. These matters constitute classified information that is specifically authorized by Executive order to be kept secret in the interest of national defense and is, in fact, properly classified pursuant to such Executive order. Accordingly, the Secretary of the Navy has determined in writing that the public interest requires that all sessions of the meeting be closed to the public because they will be concerned with matters listed in section 552b(c)(1) of title 5, United States Code.

For further information concerning this meeting, contact: Commander Robert B. Vosilus, U.S. Navy, Executive Secretary of the CNO Executive Panel Advisory Committee, 2000 North Beauregard Street, Room 392, Alexandria, VA 22311, telephone no. (202) 756-1205.

Dated: July 11, 1979.

P. B. Walker,

Captain, JAGC, U.S. Navy Deputy Assistant Judge Advocate General (Administrative Law).

[FR Doc. 79-22589 Filed 7-20-79; 8:45 am]

BILLING CODE 3810-71-M

Office of the Secretary

Privacy Act of 1974; Notice of Systems of Records: Amendments

Correction

In FR Doc. 79-20389, appearing at page 38967 in the issue of Tuesday, July 3, 1979, on page 38987, make the following change:

"SYSTEMS EXEMPTED FROM CERTAIN PROVISIONS OF THE ACT:

None.

SYSTEM NAME:"

should be corrected to read,

"SYSTEMS EXEMPTED FROM CERTAIN PROVISIONS OF THE ACT:

None.

DWHS P 19

SYSTEM NAME:"

BILLING CODE 1505-01-M

DELAWARE RIVER BASIN COMMISSION

Comprehensive Plan; Public Hearing

Notice is hereby given that the Delaware River Basin Commission will hold a public hearing on Wednesday, July 25, 1979, commencing at 2:00 p.m. The hearing will be a part of the Commission's regular July business meeting which is open to the public. Both the hearing and the meeting will be held at the Raphael Peale Room, Holiday Inn, 18th and Market Streets, Philadelphia, Pennsylvania. The subject of the hearing will be applications for approval of the following projects as amendments to the Comprehensive Plan pursuant to Article 11 of the compact and/or as project approvals pursuant to Section 3.8 of the Compact.

1. *Chester County Water Resources Authority (D-73-87 CP(2).* A flood damage reduction project located in Wallace Township, Chester County, Pa. A dam designated as PA-432 (Barneston Project) will be constructed on the East Branch Brandywine Creek as part of the Brandywine Creek Watershed Project. The 42-foot high structure will provide approximately 2,200 acre-feet of storage space designed to reduce flood damages in downstream areas.

2. *Lower Frederick Township (D-78-41 CP).* A wastewater treatment project to serve the Spring Mount area in Lower Frederick Township, Montgomery County, Pa. A treatment plant will provide 92% removal of BOD from wastewater flow of up to 160,000 gallons per day. Treated effluent will discharge to Perkiomen Creek.

3. *Citizens Utilities Water Company of Pennsylvania (D-79-13 CP).* A well water supply project in Spring Township to serve Lower Heidelberg, South Heidelberg and Spring Townships, and several adjacent boroughs in Berks County, Pa. Designated as Well No. 21, the new facility is expected to yield about 470,000 gallons per day that will be used to meet increased demands in the company's service area.

4. *City of Trenton (D-79-22 CP).* A project to upgrade the sewage treatment plant in the City of Trenton, Mercer County, N.J. Modifications will provide for treatment capacity of 20 million gallons per day and removal of about 89% BOD. Treated effluent will discharge to the Delaware River.

5. *Northampton Borough Municipal Authority (D-79-35 CP).* A water supply project involving a surface water diversion to augment public supplies in the authority's service area in Northampton, North Catasauqua and Coplay Boroughs in Northampton County, and portions of Whitehall Township in Lehigh County, Pa. Applicant proposes to increase total diversions from about 2 to 6 million gallons per day and will draw from Spring Creek and/or the Lehigh River.

6. *City of Wilmington (D-79-36 CP).* A project to regionalize water supply service within the service areas of the City of Wilmington, City of Newark, Wilmington Suburban Water Company and Artesian Water Company in northern New Castle County, Del. Distribution system interconnections, and water transfers via Red Clay Creek, will be provided to permit the City of Wilmington to provide water to adjacent systems.

7. *City of Bethlehem (D-79-45 CP).* An urban renewal project involving restoration of an historic building in the City of Bethlehem, Northampton County, Pa. The City Department of Community Development proposes to restore the Grist Mill which is located on the 100-year flood plain of Monocacy Creek, a tributary of the Lehigh River. The Grist Mill is included on the National Register of Historic Places.

8. *Pennsylvania Gas & Water Company (D-62-4(Rev.)).* A project to increase the maximum daily water withdrawal from Bear Creek, a tributary of the Lehigh River, for public water supplies in portions of Susquehanna, Wayne, Lackawanna and Luzerne Counties, Pa. The company proposes to increase its maximum daily withdrawal to 13 million gallons per day. The previously approved average daily and yearly withdrawals will remain unchanged.

9. *Magnesium Elektron Inc. (D-76-91).* A wastewater discharge from the company's processing plant located in Kingwood Township, Hunterdon County, N.J. Treated wastewater will discharge to Wickecheoke Creek which runs into the Delaware and Raritan Canal Feeder. The discharge of dissolved solids would be in accordance

with limitations, treatment requirements and abatement schedules set forth in a stipulation among the Commission, the State of New Jersey and Magnesium Elektron Inc.

10. *Mannington Mills, Inc. (D-77-66).* A well water supply project to be used for industrial purposes at the company's facility in Mannington Township, Salem County, N.J. A new well (#4) will be developed as a replacement well. When combined with an existing well, the new facility will provide for a combined groundwater withdrawal of 11.million gallons per month.

11. *Keystone Coke Co. (D-78-60).* Modifications to the company's existing waste treatment facilities located in Upper Merion Township, Montgomery County, Pa. Treatment facilities will be modified to handle ammonia liquor from the coke plant. A wastewater flow of about 150,000 gallons per day will discharge to the Schuylkill River.

12. *U.S. Steel Corp. (D-78-66).* Modification of the corporation's existing wastewater treatment facilities at the Fairless Works, Falls Townships, Bucks County, Pa. Electrolytic tinning and chrome coating wastewater will be diverted to the oil interception plant. Treated effluent of approximately 650,000 gallons per day will discharge to the Delaware River.

13. *U.S. Steel Corp. (D-78-67).* Modification of the corporation's existing wastewater treatment facilities at the Fairless Works, Falls Township, Bucks County, Pa. The facility is designed to separate contaminated and non-contaminated blast furnace cooling water for treatment. Treated effluent of approximately 1.3 million gallons per day will discharge to the Delaware River.

14. *U.S. Steel Corp. (D-78-68).* Modification of the corporation's existing wastewater treatment facilities at the Fairless Works, Falls Township, Bucks County, Pa. Pipe and wire mills facilities will be modified to divert wastewater to the oil interception plant. Treated effluent of approximately 660,000 gallons per day will discharge to the Delaware River.

15. *Jersey Central Power and Light Company (D-78-93).* Modification to the waste treatment facility at the company's Gilbert Station in Holland Township, Hunterdon County, N.J. Additional treatment facilities will be installed to bring effluent quality characteristics into conformance with applicable discharge criteria. Treatment will be provided to a wastewater flow of 288,000 gallons per day which is discharged to the Delaware River.

16. *Robert I. Hallock (D-79-20).* A well water supply project at the subject farm in Plumstead Township, Ocean County, N.J. The applicant requests approval of a maximum withdrawal of 6 million gallons per month, which will be used for irrigation of crops.

17. *Merck Sharp and Dohme (D-79-23).* A well water supply project to provide new supplies at the company's pharmaceutical facility in West Point, Upper Gwynedd Township, Montgomery County, Pa. The applicant requests approval of a withdrawal of up to 240,000 gallons per day which will be used for process water.

18. *Lukens Steel Company (D-79-26).* The applicant proposes to reactivate the rolling mill complex formerly owned by the Alan Wood Steel Company in Conshohocken, Montgomery County, Pa. The project involves withdrawal of about 2.6 million gallons per day of water from the Schuylkill River, and an effluent discharge of about 2 million gallons per day into the river through existing waste treatment facilities.

19. *Angelo Spadoni (D-79-39).* A well water supply project at the subject farm in Vineland, Cumberland County, N.J. The applicant requests approval of a maximum withdrawal of 6 million gallons per month to be used for irrigation of crops.

20. *Essex Chemical Corp. (D-79-46).* An industrial wastewater discharge project at the company's facility in Paulsboro, Gloucester County, N.J. Approximately 2.2 million gallons per day of cooling water, boiler blowdown and floor drain water will be monitored and neutralized and discharged to the Delaware River.

Documents relating to the above-listed projects may be examined at the Commission's offices. Persons wishing to testify at this hearing are requested to register with the Secretary prior to the date of the hearing.

W. Brinton Whitall,
Secretary.
July 12, 1979

[FR Doc. 79-22500 Filed 7-20-79; 8:45 am]
BILLING CODE 6360-01-M

DEPARTMENT OF ENERGY

Economic Regulatory Administration

Action Taken on Consent Orders

AGENCY: Economic Regulatory Administration, DOE.

ACTION: Notice of Action Taken on Consent Orders.

SUMMARY: The Economic Regulatory Administration (ERA) of the Department of Energy (DOE) hereby gives Notice that Consent Orders were entered into between the Office of Enforcement, ERA, and the firms listed below during the month of June. The Consent Orders represent resolutions of outstanding compliance investigations or proceedings by the DOE and the firms which involve a sum of less than $500,000 in the aggregate, excluding penalities and interest. For Consent Orders involving sums of $500,000 or more, Notice will be separately published in the Federal Register. These Consent Orders are concerned exclusively with payment of the refunded amounts to injured parties for alleged overcharges made by the specified companies during the time periods indicated below through direct refunds or rollbacks of prices.

For further information regarding these Consent Order, please contact: Mr. Wayne I. Tucker, District Manager, Southwest District Enforcement, Department of Energy, P.O. Box 35228, Dallas, Texas 75235, (214) 749-7627.

Firm name and address	Refund amount	Product	Period covered	Recipients of refund
Nordan & Co., 711 NBC Building, San Antonio, TX 78205.	$22,500 00	Crude oil	September 1973 to January 1976.	Exxon.

Issued in Dallas, Texas on the 10th day of July, 1979.

Wayne I. Tucker,
District Manager of Enforcement, Southwest District.

[FR Doc. 79-22670 Filed 7-20-79; 8:45 am]
BILLING CODE 6450-01-M

Foster Oil Co.; Proposed Remedial Order

Pursuant to 10 CFR 205.192(c), the Economic Regulatory Administration (ERA) of the Department of Energy hereby gives notice of a Proposed Remedial Order which was issued to Foster Oil Company. This Proposed Remedial Order charges Foster with pricing violations in the amount of $107,679.58 in sales of No. 1 and 2 fuel oils and motor gasoline during the time period November 1, 1973, through April 30, 1974, in the State of Michigan.

A copy of the Proposed Remedial Order, with confidential information deleted, may be obtained from Robert D. Gerring, District Manager of Enforcement, 324 East 11th Street, Kansas City, Missouri 64106. On or before August 6, 1979, any aggrieved person may file a Notice of Objection with the Office of Hearings and Appeals, 2000 M Street, NW., Washington, D.C. 20461, in accordance with 10 CFR 205.193.

Issued in Kansas City, Missouri, on the 11th day of July 1979.

Lindell J. Williams,

Acting District Manager, Central Enforcement District.

[FR Doc. 79-22671 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

Federal Energy Regulatory Commission

[Docket No. ER79-501]

Arizona Public Service; Filing of Revision to Agreement

July 17, 1979.

The filing Company submits the following:

Take notice that on July 9, 1979, Arizona Public Service Company (APS) tendered for filing revised Exhibit "B" dated May 31, 1979 to the wholesale power agreement between Citizens Utilities Company (CUC) and Arizona Public Service Company (APS) respectively, previously designated APS-FPC Rate Schedule No. 50. This revision of Exhibit "B" of the Agreement revised the expected contract demands through 1989.

Any person desiring to be heard or to protest said filing should file a petition to intervene with the Federal Energy Regulatory Commission, 825 North Capitol St., NE, Washington, DC 20426, in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before August 7, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22613 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-502]

Arizona Public Service Co.; Filing of Revision to Agreement

July 17, 1979.

The filing Company submits the following:

Take notice that on July 9, 1979, Arizona Public Service Company (APS) tendered for filing revised Exhibit "A" dated June 14, 1979 to the wholesale power agreement between United States Bureau of Indian Affairs (San Carlos Indian Irrigation Project) and Arizona Public Service Company (APS) respectively, previously designated APS-FPC Rate Schedule No. 66. This revision of Exhibit "A" of the Agreement revises contract demands for 1981 and 1982 and adds the contract demand for the year 1983.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol St., NE, Washington, DC 20426, in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before August 7, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22614 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-508]

Boston Edison Co.; Filing

July 17, 1979.

The filing Company submits the following:

Take notice that on July 12, 1979, Boston Edison Company ("Edison") tendered for filing a May 30, 1979 Amendment to its Rate Schedule FPC No. 71. That rate schedule is an October 27, 1972 agreement providing for the sale of system capacity by Edison to Fitchburg Gas and Electric Light Company ("Fitchburg") in the amount of 40 MW. Edison states that the amendment extends the termination date of the agreement from October 31, 1981 to October 31, 1986. All other terms of the agreement remain unchanged. Edison requests an effective date of October 1, 1979.

Edison states that copies of this filing were served upon Fitchburg and upon the Massachusetts Department of Public Utilities.

Any person desiring to be heard or to protest said application should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before August 7, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22615 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Project No. 2904]

Cities of Anaheim and Riverside; Application for Preliminary Permit

July 9, 1979.

Take notice that the Cities of Anaheim and Riverside (Applicants) filed on January 16, 1979, and amended on April 11, and May 14, 1979, an application for a preliminary permit [pursuant to the Federal Power Act, 16 U.S.C. § 791(a)—825(r)] for a proposed water power project to be known as the Balsam Meadow Project, FERC No. 2904, located on the North Fork of Stevenson Creek in Fresno County, California, in the vicinity of Fresno. The project would affect lands of the United States in Sierra National Forest. Correspondence with the Applicants should be directed to: Sandra J. Strebel, Esq., Spiegel & McDiarmid, 2600 Virginia Avenue, N.W., Washington, D.C. 20037. Copies of such correspondence should be sent to Peter K. Matt, Esq., and Cynthia Bogorad, Esq., at the same address and to the City of Anaheim, 518 South Anaheim Boulevard, Anaheim, California 92805 and the City of Riverside, Department of

Public Utilities, City Hall, 3900 Main Street, Riverside, California 92522.

Project Description.—The project would consist of: 1) a 5,600-foot-long tunnel originating at the outlet of Tunnel No. 7 (the existing Huntington-Pitman-Shaver conduit of Project No. 67) and leading to Balsam Forebay; 2) an 1,800 acre-foot reservoir (Balsam Forebay) to be formed by a 100-foot-high dam on the West Fork of Balsam Creek near its point of origin; 3) a two-mile-long tunnel-penstock conduit from the forebay to the powerhouse; and 4) a powerhouse, containing a 140-MW generating unit, to be located on the north shore of Shaver Lake (also part of Project No. 67) near the outlet of the North Fork of Stevenson Creek.

Applicant's proposal is in competition with an application for preliminary permit filed on September 14, 1978, by Southern California Edison Company (Project No. 2868).

Proposed Scope and Cost of Studies Under Permit.—The work proposed under this preliminary permit includes initiating data gathering, surveys and environmental assessment studies, formulating preliminary plans, and conducting such other studies as may be necessary in anticipation of filing an application for a license to construct the proposed project. The cost of the work proposed to be performed under the permit has not been determined. Applicants suggest, based on other estimates, that $500,000 may be a reasonable estimate of the cost of the studies for this project.

Purpose of Project.—Applicants own and operate electric distribution systems for the purpose of providing retail electric service within their boundaries. Applicants intend to use power from the proposed project in their utility operations in California.

Purpose of Preliminary Permit.—A preliminary permit does not authorize construction. A permit, if issued, gives the Permittee, during the term of the permit, the right of priority of application for license while the Permittee undertakes the necessary studies and examinations to determine the engineering, economic, and environmental feasibility of the proposed project, the market for power, and all other necessary information for inclusion in an application for a license.

Agency Comments.—Federal, State and local agencies that receive this notice through direct mailing from the Commission are invited to submit comments on the described application for preliminary permit. (A copy of the application may be obtained directly from the Applicant.) Comments should be confined to substantive issues relevant to the issuance of a permit and consistent with the purpose of a permit as described in this notice. No other formal request for comments will be made. If an agency does not file comments within the time set below, it will be presumed to have no comments.

Protests and Petitions to Intervene.—Anyone desiring to be heard or to make any protest about this application should file a petition to intervene or a protest with the Federal Energy Regulatory Commission, in accordance with the requirements of the Commission's Rules of Practice and Procedure, 18 CFR, § 1.8 or 1.10 (1978). In determining the appropriate action to take, the Commission will consider all protests filed, but a person who merely files a protest does not become a party to the proceeding. To become a party or to participate in any hearing, a person must file a petition to intervene in accordance with the Commission's Rules.

Any protest, petition to intervene, or agency comments must be filed on or before September 17, 1979. The Commission's address is: 825 North Capitol Street, N.E., Washington, D.C. 20426.

The application is on file with the Commission and is available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22610 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Project No. 2745]

City of Santa Clara, Calif.; Application for Major License

July 16, 1979.

Take notice that an application for a major license was filed on April 4, 1974, under the Federal Power Act (16 U.S.C. 791(a)–825(r)), by the City of Santa Clara, California (Applicant) for the Mokelumne River Project No. 2745. The project is located in Alpine, Amador, and Calaveras Counties, California on the Mokelumne, North Fork Mokelumne, and Bear Rivers. The project affects public lands of the United States within the Eldorado, Stanislaus, and Toiyabe National Forests. Correspondence regarding the application should be sent to: Mr. D. R. Von Raesfeld, City Manager, City of Santa Clara, 1500 Warburton Avenue, Santa Clara, California 95050.

The Mokelumne River Project, which was originally licensed in 1925, is currently operated by Pacific Gas and Electric Company (PG&E). The original license expired on November 23, 1975. PG&E continues to operate the project in accordance with the terms of annual licenses issued by this Commission pursuant to section 15 of the Federal Power Act (16 U.S.C. 808(a)). On December 26, 1972, PG&E filed an application for a new major license for the project. Thus, the City of Santa Clara's application for the Mokelumne River Project competes with the application filed by PG&E.

The Mokelumne River project has a total installed capacity of 192,750 kW and consists of:

(A) *Storage Dams and Reservoirs*—(1) Upper Blue Lake Dam, an earth-fill dam 837 feet long and 31 feet high, containing a 51-foot-wide spillway and two 18-inch-diameter steel outlet pipes through the dam; (2) Upper Blue Lake Reservoir having a storage capacity of 7,300 acre-feet and a surface area of 343 acres at elevation 8,137.5 feet (all elevations are U.S.G.S. datum); (3) Lower Blue Lake Dam, an earth-fill dam 1,063 feet long and 40 feet high, containing a 60-foot-wide spillway and two 30-inch-diameter steel outlet pipes through the dam; (4) Lower Blue Lake Reservoir having a storage capacity of 5,091 acre-feet and a surface area of 198 acres at elevation 8,053.4 feet; (5) Twin Lake Dam, an earth-fill dam 1,520 feet long and 22 feet high, containing two 12-inch-diameter steel outlet pipes through the dam; (6) Twin Lake Spillway, 18 feet wide, located approximately 4,000 feet east of Twin Lake Dam; (7) Twin Lake Reservoir having a storage capacity of 1,207 acre-feet and a surface area of 106 acres at elevation 8,144.7 feet; (8) Meadow Lake Dam, a rock-fill dam 775 feet long and 77 feet high, containing a 45-foot-wide spillway and two 30-inch-diameter steel outlet pipes through the dam; (9) Meadow Lake Reservoir having a storage capacity of 5,656 acre-feet and a surface area of 140 acres at elevation 7,774.4 feet; (10) Upper Bear River Dam, a rock-fill dam 760 feet long and 77 feet high, containing a 354-foot-wide spillway and three 16-inch-diameter steel outlet pipes through the dam; (11) Upper Bear River Reservoir having a storage capacity of 6,959 acre-feet and a surface area of 169 acres at elevation 5,876 feet; (12) Lower Bear River Dam No. 1, a rock-fill dam 979 feet long and 249 feet high, and Dam No. 2, a rock-fill dam 865 feet long and 145 feet high; (13) a spillway, 14 feet wide and 316 feet long, located in solid rock between the Lower Bear River Dams; (14) an outlet tunnel, 10 feet wide, 12 feet high and 1,085 feet long, passing beneath the left abutment of Dam No. 1 and discharging into the Bear River; (15) Lower Bear River Reservoir having a storage capacity of 49,079 acre-feet and a surface area of 727 acres at elevation 5,818.2 feet; (16) Salt Springs Dam, a rock-fill dam 1,257 feet long and 328 feet high; (17) a 480-foot-wide spillway, controlled by radial gates, located adjacent to Salt Springs Dam; (18) an outlet tunnel, 19 feet in diameter, passing beneath the right abutment of Salt Springs Dam; and (19) Salt Springs Reservoir having a storage capacity of 141, 857 acre-feet and a surface area of 963 acres at elevation 3,959.2 feet.

(B) *Salt Springs Development*—(1) a tunnel connected to a penstock, 475 feet long, diverting water from the Salt Springs Reservoir to the powerhouse; (2) Salt Springs Powerhouse containing a 29,700-kW generating unit and a 9,350-kW generating unit; (3) an outdoor substation; and (4) a 16.5-mile-long, 115-kV transmission line.

(C) *Tiger Creek Development*—(1) Tiger Creek Conduit extending 17.8 miles along the North Fork Mokelumne River from the Salt Springs Powerhouse to Tiger Creek Regulator Dam and Reservoir, thence 2.52 miles to Tiger Creek Forebay Dam and Reservoir; (2) five conduits diverting flows into the Tiger Creek Gonduit from Cole Creek, Bear River, Beaver Creek, East Panther Creek, and West Panther Creek; (3) a penstock, 4,940 feet long, extending from the Tiger Creek Forebay to the Tiger Creek Powerhouse; (4) Tiger Creek Powerhouse containing two 25,500-kW generating units; (5) Tiger Creek Afterbay Dam and Reservoir; (6) an outdoor substation; and (7) two 230-kV transmission lines, one 23.2 miles long and the other 13.8 miles long.

(D) *West Point Development*—(1) West Point Tunnel, 12.8 feet wide and 15.6 feet high, extending 2.73 miles from the Tiger Creek Afterbay; (2) a 650-foot-long penstock extending from the tunnel to the powerhouse; (3) West Point Powerhouse containing a 13,600-kW generating unit; (4) an outdoor substation; and (5) a 23.5-mile-long, 60-kV transmission line.

(E) *Electra Development*—(1) a diversion dam near the West Point Powerhouse; (2) Electra Tunnel, 12.8 feet wide and 15.6 feet high, extending 8.15 miles from the West Point Powerhouse Tailrace to Tabeaud Reservoir; (3) Tabeaud Reservoir having a capacity of 1,158 acre-feet; (4) a power conduit, consisting of 2,900 feet of tunnel and 3,000 feet of penstock, extending from Tabeaud Reservoir to the Electra Powerhouse; (5) Electra Powerhouse containing three 29,700-kW generating units; (6) a concrete afterbay dam below the powerhouse; and (7) an outdoor substation.

The Mokelumne River Project has the following existing recreational facilities; 63 camp units at four locations at or near the Upper and Lower Blue Lakes; picnic areas near Tiger Creek, Lake Tabeaud, and Salt Springs; and the facilities at Lower Bear River Reservoir which include the Bear River Resort, two campgrounds, one picnic area, a summer home tract, a Boy Scout camp, 97 campground units, and three unimproved boat launching sites.

Applicant proposes to develop the following additional recreational facilities: two campgrounds, the first phase of a group camp, two picnic areas, a parking lot, and a visitor's station near the Upper and Lower Blue Lakes; 10-unit boat access campground and a 25-unit overnight campground near the Lower Bear Reservoir; a nature trail at Lake Tabeaud and fishing access areas at Electra Tunnel Outlet and Mill Creek.

Applicant proposes to use the energy output of the project within its system and the integrated electrical system of the Northern California Power Agency.

Anyone desiring to be heard or to make any protests about this application should file a protest or a petition to intervene with the Federal Energy Regulatory Commission, in accordance with the requirements of the Commission's Rules of Practice and Procedure ("Rules"), 18 CFR § 1.10 or § 1.8 (1977). In determining the appropriate action to take, the Commission will consider all protests filed, but a person who merely files a protest does not become a party to the proceeding. To become a party, or to participate in any hearing, a person must file a petition to intervene in accordance with the Commission's Rules. Any protest or petition to intervene must be filed on or before September 14, 1979. The Commission's address is: 825 N. Capitol Street, N.E., Washington, D.C. 20426.

The application is on file with the Commission and is available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22617 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-503]

Florida Power Corp.; Contract Filing

July 17, 1979.

The filing Company submits the following:

Take notice that on July 10, 1979, Florida Power Corporation ("Florida Power") tendered for filing a Contract for Interchange Service ("Contract") between Utilities Commission City of New Smyrna Beach and Florida Power. Florida Power states that the Contract provides for economy energy interchange service. Florida Power requests a waiver of the sixty-day notice requirement and that the Contract be permitted to become effective on July 10, 1979 so that the parties may immediately have the opportunity of buying and selling economy energy.

Florida Power further states that copies of the Contract were served upon the Utilities Commission City of New Smyrna Beach and the Florida Public Service Commission.

Any person desiring to be heard or to protest said application should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before August 7, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22618 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-505]

Hartford Electric Light Co.; Filing

July 16, 1979.

The filing Company submits the following: Take notice that on July 11, 1979, The Hartford Electric Light Company ("HELCO") tendered for filing an initial rate schedule of an exchange agreement (the "Agreement") between HELCO and Central Maine Power Company ("CMP"). The Agreement, dated as of May 19, 1978, provides for CMP to exchange capacity from its system, based on the availability of the Maine Yankee Nuclear Generating Unit, for gas turbine capacity from the HELCO Units located at South Meadow Generating Station in Hartford, Connecticut.

The Agreement provides that the parties will determine prior to 11:00 p.m.

on Friday of each week during the Term of the Agreement whether it is economically advantageous to both parties that an exchange, pursuant to the Agreement, shall take place during that week. HELCO will pay charges to CMP in an amount equal to the kilowatts of capacity exchanged for each hour during the week that an exchange takes place times $0.0120 per kilowatt-hour, subject to the operation of the Maine Yankee Unit located in Wiscasset, Maine at or above 625,000 kilowatt-hours per hour. CMP will pay HELCO's incremental cost of producing energy from the HELCO units plus a Variable Maintenance Charge for each hour times the CMP entitlement percentage in the HELCO units for any hours during the exchange that the HELCO units were actually operated by the New England Power Exchange (NEPEX).

HELCO and CMP request an effective date of May 19, 1978 for the Agreement.

CMP has filed a certificate of concurrence in this docket.

The Agreement has been executed by the CMP and by HELCO and copies have been mailed to each of them.

HELCO further states that the filing is in accordance with Section 35 of the Commission's Regulations.

Any persons desiring to be heard or to protest said filing should file a petition to intervene or protest for the Federal Energy Regulatory Commission, 825 North Capitol Street, NE, Washington, D.C. 20426 in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before August 6, 1979. Protests will be considered by the Commission in determining appropriate action be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22619 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Project No. 2930]

Idaho Power Co.; Application for Preliminary Permit

July 9, 1979.

Take notice that on May 11, 1979, Idaho Power Company (Applicant) filed an application for a 36-month preliminary permit [pursuant to the Federal Power Act, 16 U.S.C. § 791(a)-825(r)] for a proposed water power project to be known as the North Fork of the Payette Project FERC No. 2930, and located on the North Fork of the Payette River in Valley and Boise Counties, Idaho near Boise. The project would affect lands of the United States in the Boise National Forest. Correspondence with the Applicant should be directed to: Mr. Lee S. Sherline, Leighton & Sherline, Suite 803, 1701 K Street, NW., Washington, D.C. 20006. Copies of such correspondence should be sent to Mr. Paul L. Jauregui, Secretary and General Counsel, Idaho Power Company, 1220 Idaho Street, Boise, Idaho 83707.

Project Description—The project would consist of two developments as follows: (1) the Ferncroft development, comprising a diversion weir, to be located about three miles downstream on Smiths Ferry, which would divert up to 2550 cfs of water into a 38,000-foot-long tunnel terminating at an underground surge tank; a pressure tunnel from the surge tank to an underground powerhouse containing three hydroelectric generating units with a total capacity of 165,000 kW; and a 2100-foot-long tailrace tunnel discharging into the river about 400 feet downstream of the confluence with Howell Creek; and (2) the Banks development, comprising a diversion weir, to be located about 1600 feet downstream of the Howell Creek confluence, which would divert up to 2550 cfs of water into a 22,200-foot-long tunnel terminating at an underground surge tank; a pressure tunnel from the surge tank to an underground powerhouse containing three hydroelectric generating units with a total capacity of 93,000 kW; and a 570-foot-long tailrace tunnel discharging into the river near its confluence with Phillips Creek in the vicinity of Banks.

A minimum flow of 50 cfs would be maintained in the river downstream of each development.

Proposed Scope and Cost of Studies Under Permit—During the term of the permit, Applicant proposes to perform the following activities: Engineering—collection, evaluation, and updating of existing studies and geological reconnaissance of proposed sites ($18,000); drilling and on-site investigation ($300,000); hydrologic studies ($8000); final site selection studies ($35,000); and construction design and cost studies ($300,000). Environmental—environmental data collection; description of existing environment; analysis of the environmental impact of the preferred alternatives; development of plans to mitigate the impacts of the project; and preparation of a report containing information sufficient to satisfy Exhibit W requirements in any license application. Applicant estimates that the environmental studies would take about a year to complete and would cost about $200,000.

Purpose of Project—Power from the project would be distributed for residential, farm, commercial, industrial, municipal, public utility, and interchange uses and purposes through Applicant's interconnected system in Idaho, Oregon, Nevada, and Wyoming.

Purpose of Preliminary Permit—A preliminary permit does not authorize construction. A permit, if issued, gives the Permittee, during the term of the permit, the right of priority of application for license while the Permittee undertakes the necessary studies and examinations to determine the engineering, economic, and environmental feasibility of the proposed project, the market for power, and all other necessary information for inclusion in an application for a license.

Agency Comments—Federal, state, and local agencies that receive this notice through direct mailing from the Commission are invited to submit comments on the described application for preliminary permit. (A copy of the application may be obtained directly from the Applicant.) Comments should be confined to substantive issues relevant to the issuance of a permit and consistent with the purpose of a permit as described in this notice. No other formal request for comments will be made. If an agency does not file comments within the time set below, it will be presumed to have no comments.

Protests and Petitions to Intervene—Anyone desiring to be heard or to make any protest about this application should file a petition to intervene or a protest with the Federal Energy Regulatory Commission, in accordance with the requirements of the Commission's Rules of Practice and Procedure, 18 CFR, § 1.8 or 1.10 (1978). In determining the appropriate action to take, the Commission will consider all protests filed, but a person who merely files a protest does not become a party to the proceeding. To become a party or to participate in any hearing, a person must file a petition to intervene in accordance with the Commission's Rules.

Any protest, petition to intervene, or agency comments must be filed on or before September 10, 1979. The Commission's address is: 825 North Capitol Street, N.E., Washington, D.C. 20426.

The application is on file with the Commission and is available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22620 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-506]

Iowa Southern Utilities Co.; Tariff Change

July 16, 1979.

The filing Company submits the following:

Take notice that Iowa Southern Utilities Company, on July 10, 1979, tendered for filing proposed changes in its FERC Electric Service Tariff Volume No. 1, Sheets No. 1, 2 and 11. The proposed changes would increase revenues from jurisdictional sales and service by $197,416 based on the 12-month period ending June 30, 1980.

The reason for the proposed increase in the Company's increased cost of doing business. Higher costs are being incurred for power supplies and the increasing interest rate on borrowed money. There have also been increases in the cost of material, labor and transportation equipment.

Copies of the filing were served upon Albia Light and Railway Company and to the Cities of Seymour, Afton, Eldon, Orient, Danville and New London. A copy of the filing has also been mailed to the Iowa State Commerce Commission.

Any person desiring to be heard or to protest said application should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before August 6, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestant parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22621 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. CP79-366]

Mississippi River Transmission Corp.; Application

July 13, 1979.

Take notice that on June 15, 1979, Mississippi River Transmission Corporation (Applicant), 9900 Clayton Road, St. Louis, Missouri 63124, filed in Docket No. CP79-366 an application pursuant to Section 7 of the Natural Gas Act and Section 157.7(g) of the Regulations thereunder (18 CFR 157.7(g)) for a certificate of public convenience and necessity authorizing the construction and for permission and approval to abandon for a twelve-month period commencing August 16, 1979, and the operation of various field compression and related metering and appurtenant facilities, all as more fully set forth in the application which is on file with the Commission and open to public inspection.

The stated purpose of this budget-type application is to augment Applicant's ability to act with reasonable dispatch in the construction, acquisition, relocation, and operation and abandonment of facilities which would not result in changing Applicant's system salable capacity or service from that authorized prior to the filing of the instant application.

Applicant states that the total cost of the proposed cosntruction and abandonment under Section 157.7(g) would not exceed $2,000,000 and no single project would exceed $500,000. Applicant proposes to finance the costs of said facilities from internally generated funds.

Any person desiring to be heard or to make any protest with reference to said application should on or before August 2, 1979, file with the Federal Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petition to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no petition to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that a grant of the certificate and permission and approval for the proposed abandonment are required by the public convenience and necessity. If a petition for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Applicant to appear or be represented at the hearing.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22622 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Project No. 2919]

Municipal Electric Authority of Georgia; Application for Preliminary Permit

July 16, 1979.

Take notice that on March 16, 1979, the Municipal Electric Authority of Georgia filed an application for preliminary permit (Pursuant to the Federal Power Act, 16 U.S.C. Sections 791(a)-825(b)) for a proposed hydroelectric project, to be known as the Savannah Bluff Lock and Dam Project, FERC No. 2919, located on the Savannah River in Richmond County, Georgia. The proposed project would be located on a navigable waterway of the United States and occupy, in whole or in part, lands of the United States under the control of the U.S. Army Corps of Engineers, and would use a government dam. Correspondence with the Applicant should be directed to: Mr. Donald L. Stokley, General Manager, Municipal Electric Authority of Georgia, 800 Peachtree Center—South Tower, 225 Peachtree Street, Atlanta, Georgia 20203 and Mr. L. Clifford Adams, Jr., General Counsel, 66 Luckie Street, N.W.—Suite 520, Atlanta, Georgia 30303.

Purpose of Project—Electric energy produced by the project would be utilized in meeting the bulk power supply requirements of the political subdivisions served by the Applicant.

Proposed Scope and Cost of Studies Under Permit—Applicant seeks the issuance of a preliminary permit for a period of 36 months, during which time the Applicant proposes to study the feasibility of installing hydroelectric generating units at the existing New Savannah Bluff Lock and Dam of the U.S. Army Corps of Engineers. Applicant proposes to develop preliminary designs, conduct geologic explorations, collect environmental data, and prepare an application for FERC license. Applicant estimates the cost of studies under the permit would be $58,000.

Project Description—The Savannah Bluff Lock and Dam Project would consist of: (1) a powerhouse, adjacent to the Corps of Engineers navigation lock, which would contain hydroelectric generating units (number, size and type to be determined in the course of the study) having a total installed capacity of approximately 5,000 kW; (2) step-up transformers; (3) approximately 4.0 miles of 12-kV transmission line to interconnect with the existing electric distribution system; and (4) appurtenant facilities. The estimated annual output of the proposed project is 35,040,000 kWh.

Purpose of Preliminary Permit—A preliminary permit does not authorize construction. A permit, if issued, gives the permittee during the term of the permit, the right of priority of application for license while the permittee undertakes the necessary studies and examinations to determine the engineering, economic, and environmental feasibility of the proposed project, the market for the power, and all other necessary information for inclusion in an application for a license. In this instance, Applicant seeks a 36-month permit.

Agency Comments—Federal, State, and local agencies that receive this notice through direct mailing from the Commission are invited to submit comments on the described application for preliminary permit. (A copy of the Application may be obtained directly from the Applicant.) Comments should be confined to substantive issues relevant to the issuance of a permit and consistent with the purpose of a permit as described in this notice. No other formal request for comments will be made. If any agency does not file comments within the time set below, it will be presumed to have no comments.

Protests and Petitions To Intervene—Anyone desiring to be heard or to make any protest about this application should file a petition to intervene or a protest with the Federal Energy Regulatory Commission, in accordance with the requirements of the Commission's Rules of Practice and Procedure, 18 CFR Section 1.8 or Section 1.10 (1977). In determining the appropriate action to take, the Commission will consider all protests filed, but a person who merely files a protest does not become a party to the proceeding. To become a party or a person to participate in any hearing a person must file a petition to intervene in accordance with the Commission's Rules.

Any protest petition to intervene, or agency comment must be filed on or before September 20, 1979. The Commission's address is: 825 N. Capitol Street, N.E., Washington, D.C. 20426. The application is on file with the Commission and is available for public inspection.

Kenneth F. Plumb,
Secretary.

[FR Doc. 79-22623 Filed 7-20-79; 8:45 am]
BILLING CODE 6450-01-M

[Docket No. GP79-45]

State of New Mexico NGPA Determination on Southland Royalty Company Patterson "B" Com. #1 J079-7078; Preliminary Finding

Issued July 13, 1979.

On May 30, 1979, the State of New Mexico Oil Conservation Division (New Mexico) submitted to the Commission a notice of determination, which states that the Southland Royalty Company Patterson "B" Com. #1 well qualifies as a new, onshore production well under section 103 of the Natural Gas Policy Act of 1978 (NGPA). The Commission published New Mexico's notice on June 21, 1979.

A well qualifies as a new, onshore production well under section 103 of the NGPA only if, among other requirements, the surface drilling for the well began on or after February 19, 1977.

The information accompanying the determination indicates that surface drilling of the subject well commenced on May 9, 1954 and that the well was completed in a shallow reservoir on May 31, 1954. Then, between July 29, 1977 and August 1, 1977, the well was deepened to its current depth.

This evidence indicates that the surface drilling of the Southland Royalty Company "B" Com. #1 well was not begun on or after February 19, 1977. Thus, it appears that the record does not contain substantial evidence to support New Mexico's determination that the well qualifies as a new, onshore production well under section 103 of the NGPA.

Accordingly, the Commission makes a preliminary finding (pursuant to 18 C.F.R. § 275.202(a)(1)(i)) that the determination submitted by New Mexico is not supported by substantial evidence in the record on which the determination was based.

By direction of the Commission.

Kenneth F. Plumb,
Secretary.

[FR Doc. 79-22641 Filed 7-20-79; 8:45 am]
BILLING CODE 6450-01-M

[Docket No. EL78-29]

New York State Electric & Gas Corp.; Compliance Filing

July 17, 1979.

Take notice that New York State Electric & Gas Corporation (NYSEG), by letters dated May 1, 1979 and June 11, 1979 tendered for filing, pursuant to the Commission's Declaratory Order Modifying Jurisdictional Contracts issued March 28, 1979, contracts entered into between NYSEG and the following, all located in New York:

Power Authority of the State of New York
Village of Penn Yan
Village of Bath
Village of Castille
Village of Endicott
Village of Greene
Village of Groton
Village of Marathon
Village of Silver Springs
Village of Watkins Glen

Any person desiring to be heard or to protest said filing should file a protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8 and 1.10). All such protests should be filed on or before August 7, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,
Secretary.

[FR Doc. 79-22624 Filed 7-20-79; 8:45 am]
BILLING CODE 6450-01-M

[Project No. 2752]

Northern Lights, Inc.; Fixing Place and Procedures for Public Sessions

July 9, 1979.

On November 30, 1978, Northern Lights, Inc., filled an application for a major license for the Kootenai Project No. 2752 to be located on the Kootenai River between the towns of Libby and Troy, Montana. The Commission has circulated the application for agency comments and three interventions have been filed.

The Commission's staff is currently preparing a draft environmental impact statement (DEIS) on the proposed project. During the week of July 29, 1979, the staff members assigned to drafting the DEIS will be in the vicinity of the project site to obtain additional information to prepare the DEIS.

As part of this information gathering process, two public sessions will be held to allow members of the general public an opportunity to present any information they may have which should be brought to the attention of staff before the DEIS is issued. The two public sessions will be held in the Community Room, First National Bank, 504 Mineral Avenue, Libby, Montana, at 1:30 p.m. and 7:00 p.m. on July 30, 1979. Any members of the public, including parties to this proceeding, desiring to present their views or information on the proposed project may do so orally and in writing. All oral and written statements presented will be transcribed by a court reporter into the written record of the public session. These public sessions do not constitute evidentiary hearings which as of this date have not been ordered by the Commission.

To avoid confusion and to ensure that all persons wishing to present their positions can do so, the following procedures will be observed at the public meeting:

All persons desiring to be heard or wishing to submit written statements should, prior to the convening of the sessions listed above, fill out cards with their names, addresses, and the organization they represent, if any. The cards then should be given to the Commission staff member. Blank cards will be available at the entrance to the Community Room.

When a person's name is called, the person should come forward and state his name, address, and organization, if any. The cards then should be given to the Commission staff member. Blank cards will be available at the entrance to the Community Room.

When a person's name is called, the person should come forward and state his name, address, and organization, if any. If he has a written statement, he should give the reporter a copy. If an oral statement is to be given, the person should proceed to make the statement.

In cases where a person submits a written statement and also wishes to make an oral statement, the oral remarks should only summarize briefly the highlights of the written statement, since all written statements will be copied into the record as though read. The statements made at the public session do not constitute evidence, and the persons giving statements will not be subject to cross-examination.

If a person desires to make a statement for the record but is unable to be present at the time their name is called, they may leave a copy of their statement with the reporter, and such statement will be copied into the record as though read or presented orally. If for any reason a person desiring to be heard is unable to attend the public session in person, he may submit a written statement by August 10, 1979, to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and such statement will be made a part of the record of the public session.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22605 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-500]

Northern States Power Co.; Filing

July 17, 1979.

Take notice that Northern States Power Company on July 2, 1979, tendered for filing supplements to its agreements with the following communities in Wisconsin: Black River Falls, Bangor, Cornell, New Richmond, Rice Lake, Trempealeau, Westby and Whitehall.

Northern States indicates that these agreements are being changed by deleting certain words in metering section of the terms and conditions to allow flexibility in the selection of metering equipment.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before August 7, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intevene. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22626 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. CP79-385]

Northern Natural Gas Co.; application

July 16, 1979.

Take notice that on June 28, 1979, Northern Natural Gas Company (Northern), 2223 Dodge Street, Omaha, Nebraska 68102, filed in Docket No. CP79-385 an application pursuant to Section 7(b) of the Natural Gas Act for permission and approval to abandon and remove the facilities of its Ashland, Kansas, and Glenwood, Iowa, compressor stations, all as more fully set forth in the application which is on file with the Commission and open for public inspection.

It is stated that in recent years the natural gas reserves in Northern's traditional areas of supply have been declining, resulting in a decrease in winter season volumes available from such areas. In order to offset the reduced wintertime volumes from the south, Northern has entered into various storage arrangements, both on and off system, which provide for the delivery of winter season volumes into the north end of Northern's system. As a result, of the changed delivery pattern reducing the peaking volumes from the south, the compressor facilities at the Ashland station have been idled. Also, as a result of reduced summertime demand, sufficient volumes are available at Redfield for injection without utilizing the Glenwood station.

Northern does not foresee any further use of these turbine-driven units on its transmission system and therefore request authority to abandon and remove a 12,500 horsepower turbine-driven compressor and appurtenances for the Ashland station and the 5,300 horsepower turbine-driven compressor and all station facilities and structure of the Glenwood Midpoint Station. Northern states that all salvable items would be returned to stock for future use with the exception of the 2 gas turbine units which would be disposed of by sale.

Any person desiring to be heard or to make any protest with reference to said application should on or before August 7, 1979, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and procedure (18 CFR 1.8 or 1.10) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petition to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal energy Regulatory Commission by Sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no petition to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that permission and approval for the proposed abandonment are required by the public convenience and necessity. If a petition for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Applicant to appear or be represented at the hearing.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22627 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

State of Ohio NGPA Determination on Resource Exploration, Inc. Twelve Wells; Preliminary Finding

[Docket No. GP79-47]

July 13, 1979.

On May 30, 1979, the Commission received from the Ohio Department of Natural Resources, notices of determination which state that twelve Resource Exploration, Inc. wells[1] meet all the requirements of the stripper well provisions in section 108 of the Natural Gas Policy Act of 1978 (NGPA), Pub. L. No. 95-621.

According to section 108 of the NGPA, a natural gas well may qualify for stripper well status if it produced non-associated natural gas during the preceding 90-day production period at a rate which did not exceed an average of 60 Mcf per production day during the production period.

Section 271.804(c) of the interim regulations requires an application for determination for stripper well status be based on a 90-day production period ending within 120 days prior to the date on which the application is filed.

The records show that the 90-day production periods upon which the twelve applications are based do not end within 120 days prior to the date on which the applications were filed. Accordingly, it appears that the record does not contain substantial evidence to support the subject determinations of eligibility under section 108 of the NGPA.

In view of the above, the Commission hereby makes a preliminary finding (pursuant to section 275.202(a)(1)(i)) that the determinations submitted by the Ohio Department of Natural Resources are not supported by substantial evidence in the record on which the determinations were made.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

[FR Doc. 22642 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[1] Well name and No. and FERC control No.:
Young #1—JD79-7189.
Krebs #1—JD79-7190.
Troyer #23—JD79-7191.
Zimmerman #2—JD79-7192.
Zimmerman #4—JD79-7193.
Young #3—JD79-7194.
Miller #29—JD79-7195.
Yoder #16—JD79-7196.
Ott #1—JD79-7197.
Miller #8—JD79-7198.
Pepper #1—JD79-7199.
Scarr #1—JD79-7200.

[Docket Nos. E-7777 (Phase II) and E-7796]

Pacific Gas and Electric Co.; Compliance Filing

July 16, 1979.

Take notice that on July 5, 1979, the Southern California Edison Company tendered for filing in compliance with the Commission's order of June 14, 1979:

I. Agreements between Edison and the Department of Water and Power of the City of Los Angeles.

A. City—Edison Pacific Intertie D-C Transmission Facilities Agreement (Executed March 31, 1966).

B. City—Edison Sylmar Interconnection Agreement (Executed March 31, 1966).

C. Amendment No. 1 to City—Edison Sylmar Interconnection Agreement (Executed February 11, 1971).

II. Other Documents.

A. Agreement No. 2 to the Pacific Intertie Agreement dated March 1, 1970.

B. Midway Interconnection Agreement between Pacific Gas and Electric Company (PG&E) and Edison dated March 12, 1970.

C. Pacific Power & Light Company—California Companies Agreement for Use of Transmission Capacity dated August 1, 1967.

D. California Power & Light Company—California Companies Agreement for use of Transmission Capacity dated August 1, 1967.

E. California Companies Pacific Intertie Agreement Coordination Committee Rulings 1-41.

Also, pursuant to the Commission's order of June 14, 1979, Pacific Gas and Electric Company and San Diego Gas & Electric Company on July 5, 1979, jointly filed:

(1) United States Department of the Interior, Bureau of Reclamation, Central Valley Project, California: Contract with Pacific Gas and Electric Company for installation, operation and maintenance of facilities at Round Mountain, and for the operation and maintenance of Bureau EHV Line, dated July 31, 1967.

(2) United States Department of the Interior, Bureau of Reclamation, Central Valley Project, California: Contract with Pacific Gas and Electric Company for installation, operation and maintenance of facilities at Cottonwood Substation, dated July 31, 1967.

(3) Amendment Number Two to California Pacific Intertie Agreement, dated March 1, 1970.

(4) Midway Interconnection Agreement between Pacific Gas and Electric Company and Southern California Edison Company, dated March 12, 1970.

(5) Letter Agreement dated May 29, 1968 between Pacific Gas and Electric Company and Bureau of Reclamation.

(6) Letter Agreement dated July 9, 1969, between Pacific Gas and Electric Company and Bureau of Reclamation.

(7) Letter agreement dated November 20, 1967 between Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company.

(8) Letter Agreement dated March 1, 1970 between Pacific Gas & Electric Company, San Diego Gas & Electric Company and Southern Edison Company.

(9) The presently effective rulings of the Coordination Committee of the California Companies Pacific Intertie Agreement (Ruling Nos. 1, 6, 7, 10, 16, 17, 18, 19, 20, 22, 23, 24, 25, 30, 31, 32, 33, 36, 37, 38, 39, 40, 41, and 42).

(10) Ruling Nos. 4 and 7 of the Board of Control of the California Power Pool Agreement.

Any person desiring to be heard or to protest said filing should file a protest with the Federal Energy Regulatory Commission, 825 North Capitol St., N.E., Washington, D.C. 20426, in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such protests should be filed on or before August 3, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22628 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Project No. 77]

Pacific Gas and Electric Co.; Order Establishing Hearing and Requiring Prehearing Conference

July 5, 1979.

Background

Pacific Gas and Electric Company (PG&E) has filed an application for a new license for its Potter Valley Project No. 77. PG&E's application has been circulated for agency comment. The Commission's staff has also prepared a draft and final environmental impact statement. Seven parties have been granted intervention.[1]

The Potter Valley Project is located on the Eel and East Fork Russian Rivers in Lake and Mendocino Counties, California. The project was first constructed in 1907 and affects lands of the United States. The project consists of a storage reservoir (Lake Pillsbury), a forebay (Van Arsdale Reservoir), tunnels, penstocks and a power plant with an installed capacity of 9,040 kilowatts. Water from Lake Pillsbury is released into the Eel River and flows about 11 miles to Van Arsdale Reservoir formed by Cape Horn Dam. At the Van Arsdale Reservoir, water is passed from the Eel River Basin to the Russian River Basin by a series of tunnels and pipes leading to the powerhouse. Some of the water leaving the powerhouse is diverted for irrigation purposes, with the remaining water entering the Russian River. Water releases into the Eel River are maintained to provide a minimum of 2 cubic feet per second (cfs) below Van Arsdale reservoir.

Discussion

Since the project was constructed, the number of steelhead trout and chinook salmon using the Upper Eel River for spawning and rearing of young has generally decreased. The State and certain intervenors allege that this decline can be attributed to the flow releases from the Cape Horn dam. Various measures have been proposed to protect or enhance the runs of anadromous fish using the Upper Eel River. One enhancement measure would be to increase the flow into the Eel River from Van Arsdale Reservoir. This would, of course, reduce the flow through the powerhouse and, in turn, reduce the quantity of water entering the Russian River.

Before and after the issuance of the draft and final environmental imapct statement, our staff convened settlement conferences to discuss measures that could be implemented to enhance the steelhead trout and chinook salmon runs in the Eel River.[2] According to staff's latest letter dated June 14, 1979, the parties have not been able to resolve their differences and request that a hearing on the matter be initiated.

Hearing Issue

We find that it is appropriate and in the public interest that a hearing be held to determine what, if any, conditions should be included in a new license for the Potter Valley Project for the protection and enhancement of the steelhead trout and chinook salmon runs in the Upper Eel River. The hearing should investigate the proper allocation of water between the Eel and Russian River systems and determine if it would be appropriate to increase the current minimum flow into the Eel River from Van Arsdale reservoir.

In providing for a hearing, we recognize that there have been extensive and continuing efforts to resolve the anadromous fish problems in the Upper Eel River. The staff's latest letter dated June 14, 1979, indicates that the parties have agreed to continue their efforts to settle the disputed issues. The staff also offered guidelines for an offer of settlement based on the points of agreement reached at the last conference. Accordingly, we are directly the Presiding Administrative Law Judge to convene a prehearing conference for the purpose of considering any offer of settlement that may be forthcoming. If it appears to the presiding judge that the parties are unable to resolve their differences at the prehearing conference, he shall schedule appropriate dates for the hearing.

The Commission orders:

(A) Pursuant to the provisions of the Federal Power Act, particularly Sections 4(e), 10(a), 10(g), 15, 308, and 309, and the Commission's rules of practice and procedure, a hearing shall be held concerning all matters on the issue of what, if any, conditions the Commission should include in any new license for the Potter Valley Project No. 77 for the protection and enhancement of the steelhead trout and chinook salmon runs in the Upper Eel River.

(B) A Presiding Administrative Law Judge, to be designated by the Chief Administrative Law Judge, shall preside at the hearing in this proceeding. The Presiding Judge shall convene a prehearing conference in this proceeding at 9:30 a.m. on August 14, 1979, in a hearing room of the Federal Energy Regulatory Commission, 825 North Capitol Street, N. E., Washington, D. C. 20426.

(C) The Secretary shall cause prompt publication of this order in the Federal Register.

By the Commission.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22640 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket Nos. CI70-917, et al.]

Phillips Petroleum Company, et al.; Notice of Applications for Certificates, Abandonment of Service and Petitions To Amend Certificates[1]

July 10, 1979.

Take notice that each of the Applicants listed herein has filed an application or petition pursuant to Section 7 of the Natural Gas Act for authorization to sell natural gas in

[1] The parties in the proceeding are the California Department of Fish and Game, California Trout, Inc., Humboldt County, County of Lake, Mendocino County Russian River Flood Control and Water Conservation Improvement District, County of Sonoma/Sonoma County Water Agency, and County of Mendocino.

[2] In addition to the two conferences our staff has held concerning this proceeding, a number of other conferences and meetings have been held among the parties.

[1] This notice does not provide for consolidation for hearing of the several matters covered herein.

interstate commerce or to abandon service as described herein, all as more fully described in the respective applications and amendments which are on file with the Commission and open to public inspection.

It appears reasonable and consistent with the public interest in this case to prescribe a period shorter than 10 days for the filing of protests and petitions to intervene. Therefore, any person desiring to be heard or to make any protest with reference to said application should on or before July 18, 1979, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petition to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure a hearing will be held without further notice before the Commission on all applications in which no petition to intervene is filed within the time required herein if the Commission on its own review of the matter believes that a grant of the certificates or the authorization for the proposed abandonment is required by the public convenience and necessity. Where a petition for leave to intervene is timely filed, or where the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Applicants to appear or to be represented at the hearing.

Kenneth F. Plumb,

Secretary.

Docket No. and date filed	Applicant	Purchaser and location	Price Per Mcf	Pressure Base
CI70-917, C, June 26, 1979	Phillips Petroleum Company, 5 C4 Phillips Building, Bartlesville, Okla. 74004.	Panhandle Eastern Pipe Line Company, Douglas Plant, Powder River Basin Area of Wyoming.	(1)	14.73
CI75-42, C, June 26, 1979	Phillips Petroleum Company	Panhandle Eastern Pipe Line Company, Douglas Plant, Powder River Basin Area of Wyoming.	(1)	14.73
CI76-239, E, June 25, 1979	Gulf Oil Corporation (Succ. in Interest to Kewanee Oil Company), P.O. Box 2100, Houston, Texas 77001.	Kansas-Nebraska Natural Gas Company, Inc., Dombey Southwest Field, Sec. 28-4N-20ECM, Beaver County, Oklahoma.	(1)	14.73
CI77-168, D, June 28, 1979	Ladd Petroleum Corporation, 830 Denver Club Building, Denver, Colorado 80202.	Colorado Interstate Gas Company, Wild Rose Field, Sweetwater County, Wyoming.	Federal No. 1-22-74 Well, Sec. 22-17N-84W, Sweetwater County, Wyoming assigned to Cotton Petroleum Corporation 1-15-79.	
CI77-399, C, August 25, 1978	Tenneco Oil Company, P.O. Box 2511, Houston, Texas 77001.	El Paso Natural Gas Company, Leonard Queen South Formation, Lea County, New Mexico.	(1)	14.65
CI79-500, A, June 21, 1979	The Offshore Company, P.O. Box 2765, Houston, Texas 77001.	Southern Natural Gas Company, Mississippi Canyon Blocks 150, 151, 194 and 195, Offshore Louisiana.	(1)	15.025
CI79-501, A, June 21, 1979	The Offshore Company	Southern Natural Gas Company, West Cameron Block 330 Area, Offshore Louisiana.	(1)	15.025
CI79-502, A, June 21, 1979	Sonat Exploration Company, 3336 Richmond Avenue, Houston, Texas 77098.	Southern Natural Gas Company, West Cameron Block 330 Area, Offshore Louisiana.	(1)	15.025
CI79-503, A, June 21, 1979	Sonat Exploration Company	Southern Natural Gas Company, Mississippi Canyon Blocks 150, 151, 194 and 195, Offshore Louisiana.	(1)	15.025
CI79-506, A, June 25, 1979	Tenneco Exploration, Ltd., P.O. Box 2511, Houston, Texas 77001.	Tennessee Gas Pipeline Company, High Island Block A-336, East Addition, South Extension Area, High Island Block A-343 Field, Offshore Texas.	(1)	14.65
CI79-512, A, June 25, 1979	Exxon Corporation, P.O. Box 2180, Houston, Texas 77001.	Columbia Gas Transmission Corporation, West Delta Block 117 Field, Offshore Louisiana.	(1)	15.025
CI79-513, A, June 27, 1979	The Louisiana Land and Exploration Company, 225 Baronne Street, P.O. Box 60350, New Orleans, La. 70160.	Transco Gas Supply Company, Certain acreage located in Eugene Island Area, Block 261 Field, Blocks 261 and 262, Gulf of Mexico.	(1)	15.025
CI79-514, A, June 27, 1979	The Louisiana Land and Exploration Company, 225 Baronne Street, P.O. Box 60350, New Orleans, La. 70160.	Transco Gas Supply Company, Certain acreage located in West Cameron, Block 540 Field, Gulf of Mexico.	(1)	15.025
CI79-515, A, June 27, 1979	Louisiana Land Offshore Exploration Company, Inc., 225 Baronne Street, P.O. Box 60350, New Orleans, La. 70160.	Transco Gas Supply Company, Certain acreage located in West Cameron, Block 540 Field, Gulf of Mexico.	(1)	15.025
CI79-516, A, June 27, 1979	Mesa Petroleum Co., One Mesa Square, P.O. Box 2009, Amarillo, Texas 79189.	Michigan Wisconsin Pipe Line Company, High Island Area, Block A-474 and Block A-489, Offshore Texas.	(1)	14.66
CI79-517, B, June 27, 1979	Samedan Oil Corporation, P.O. Box 909, Ardmore, Okla. 73401.	Cities Service Gas Company, Rutledge #1 Gas Unit, Sec. 8-24N-18W, N.W. Quinlan Field, Woodward County, Oklahoma.	Depleted.	
CI79-518, E, June 28, 1979	Gulf Oil Corporation (Succ. in Interest to Kewanee Oil Company), P.O. Box 2100, Houston, Texas 77001.	Natural Gas Pipeline Company of America, Certain acreage located in the Lochridge Field, Ward County, Texas.	(1)	14.65
CI79-519, A, June 25, 1979	Texaco Inc., P.O. Box 60252, New Orleans, La. 70160.	Tennessee Gas Pipeline Company, East Cameron Area, Block 280 and the West Cameron Area, Block 509, Offshore Louisiana.	(1)	14.73
CI79-520, A, June 20, 1979	The Louisiana Land and Exploration Company	Texas Eastern Transmission Corporation, Certain acreage located in Block 522 Field, West Cameron Area, Offshore Louisiana.	(1)	15.025

Docket No. and date filed	Applicant	Purchaser and location	Price Per Mcf	Pressure Base
CI79-521, A, June 25, 1979	TransOcean Oil, Inc. (Operator), 1700 First City East, 1111 Fannin, Houston, Texas 77002.	Mid Louisiana Gas Company, MA-1 RA SuB Matherne No. 1 Well located in Sec. 44-T12S-R4E, College Point—St. James Field, St. James Parish, Louisiana.	(9)	15.025
CI79-522, A, June 25, 1979	Texaco Inc.	Columbia Gas Transmission Corporation, Blocks 642 and 643, West Cameron Area, Offshore Louisiana.	(10)	15.025

[1] Applicant is filing for the maximum lawful price under the Natural Gas Policy Act of 1978.

[2] Effective as of 7-1-78, Applicant acquired all of Kewanee's interest in acreage covered by Amendatory Agreement dated 1-3-79, which amends a contract executed by Kewanee and Kansas-Nebraska dated 10-1-75, and a contract executed by Dow Chemical Company and Kansas-Nebraska dated 10-16-75.

[3] Applicant is willing to accept the applicable national rate pursuant to Opinion No. 770, as amended.

[4] Applicant is filing under Gas Purchase and Sales Agreement dated 6-21-79.

[5] Applicant is willing to accept a certificate conditioned upon a price equal to the maximum lawful price under Section 104 of the Natural Gas Policy Act of 1978, reserving its right to collect any higher applicable NGPA rate.

[6] Applicant is filing under Section 104 of the Natural Gas Policy Act of 1978.

[7] Effective as of 7-1-78, Applicant acquired all of Kewanee's interest in properties covered by contract dated 8-21-67, as amended.

[8] Applicant is filing under Gas Purchase Contract dated 6-19-79.

[9] Applicant, a large producer, has taken over as operator of the Matherne No. 1 well effective 2-1-79 and is requesting that temporary authorization be granted effective 2-1-79. Applicant is willing to accept temporary authorization upon an initial rate prescribed under Section 104 of the Natural Gas Policy Act of 1978, provided that Applicant shall be entitled to file increases to any higher contractually authorized prices in accordance with the Natural Gas Act and the NGPA.

[10] Applicant is filing for that price prescribed by Section 109(a)(2) of the Natural Gas Policy Act of 1978.

Filing Code: A—Initial Service. B—Abandonment. C—Amendment to add acreage. D—Amendment to delete acreage. E—Total Succession. F—Partial Succession.

[FR Doc. 79-22639 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-507]

Public Service Co. of Indiana, Inc.; Filing

July 17, 1979.

The filing Company submits the following: Take notice that Public Service Company of Indiana, Inc. on July 11, 1979 tendered for filing pursuant to the Interconnection Agreement between Public Service Company of Indiana, Inc. and Southern Indiana Gas and Electric Company a Sixth Supplemental Agreement to become effective September 6, 1979.

Said Supplemental Agreement increases the demand charge for Short Term Power from 60¢ per kilowatt per week to 70¢ per kilowatt per week.

Copies of the filing were served upon Southern Indiana Gas and Electric Company and the Public Service Commission of Indiana.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions should be filed on or before August 7, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of the filing are available for public inspection at the Federal Energy Regulatory Commission.

Kenneth F. Plumb,
Secretary.

[FR Doc. 79-22629 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. CP79-374]

Southern Natural Gas Co.; Application

July 16, 1979.

Take notice that on June 20, 1979, Southern Natural Gas Company (Southern), P.O. Box 2563, Birmingham, Alabama 35202, filed in Docket No. CP79-374 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing a storage service for certain customers of Southern, the inclusion of the related storage injection requirements in Southern's Index of Requirements in its FERC Gas Tariff, a related transportation service for the storage customers, and the construction and operation of facilities necessary to perform the transportation service, all as more fully set forth in the appendix hereto and in application which is on file with the Commission and open to public inspection.

Southern states that in Opinion No. 786, the F.P.C. approved a Stipulation and Agreement which provides for the pricing of liquefied natural gas (LNG) on Southern's system on a rolled-in basis and provides for Southern to make a storage service available to its customers. Southern has arranged with ANR Storage Company (ANR) to make available storage which would enable Southern to provide the storage service called for in the Stipulation and Agreement. ANR would make storage service available to Southern on a 50 and 100-day basis. ANR's storage facilities would be located in Kalkaska County, Michigan. Accordingly, in order to arrange for the delivery to and redelivery from ANR of volumes to be stored for Southern by ANR, Southern has entered into transportation agreements with Michigan Wisconsin Pipe Line Company (Michigan Wisconsin).

Southern states that on June 12, 1978, it offered the storage service required by the Stipulation and Agreement to its jurisdictional customers on a 50-day and 100-day basis. In response to Southern's June 12, 1978 offer of storage service, Atlanta Gas Light Company (Atlanta), South Georgia Natural Gas Company, Jupiter Industries, Inc. d/b/a Chattanooga Gas Company (Chattanooga) and the City of LaGrange, Georgia (storage customers) subscribed for approximately 6.5 million Mcf of winter contract quantity out of a total offering to all customers of 16 million Mcf. Thereafter, Southern reoffered those customers the remaining difference and an additional total of approximately 5 million Mcf was subscribed to by Atlanta and Chattanooga.

Southern states that it has entered into storage service agreements with its storage customers. The storage service Southern would provide its customers pursuant to the storage service agreements tracks the storage and transportation services Southern has arranged with ANR and Michigan Wisconsin. Under the storage service agreements, gas will be provided to Southern for storage and returned from storage at Southern's Shadyside Compressor Station.

In order to arrange for the transportation of gas to be stored by Southern to and from the Shadyside delivery point all storage customers have entered into a storage transportation agreement with Southern. Pursuant to the storage transportation agreements, storage customers nominate and pay for the volumes Southern delivers at the Shadyside delivery point to be stored under the storage service agreements, plus related fuel gas. Although storage customers would have already become obliged to pay for the volumes delivered at Shadyside for storage by Southern, neither title, control nor possession of those volumes would have passed to customers at that time. Title, control and possession of gas stored and transported by Southern for storage customers would pass to those customers only when such gas is redelivered at the redelivery point(s) specified in each storage customer's storage transportation agreement with Southern. Volumes returned from storage at Shadyside by Southern, pursuant to the storage service agreements, would be returned to storage customers less appropriate fuel gas pursuant to the storage transportation agreements.

Southern requests that the certificate issued in this proceeding (i) certify said requirements for inclusion in priority-of-service category 2 of its currently effective Index of Requirements or in such other category of Southern's Index of Requirements as Southern's storage injection requirements are included at the time said requirements are filed for inclusion in Southern's tariff and (ii) provide that Southern shall file revised tariff sheets reflecting the increased requirements as discussed above to be effective as of the commencement of the services proposed by Southern herein. Southern states that only volumes up to the storage injection requirements for each storage customer originally included in the Stipulation and Agreement where Southern undertook to provide this storage service (plus appropriate fuel gas) would be included in Southern's Index of Requirements in the appropriate category.

The storage service agreements are cost of service tariffs and provide for a charge which flows through to each storage customer the percentage of Southern's charges from ANR and Michigan Wisconsin attributable to the storage and transportation services provided for the benefit of such customer. Each storage customer is also required to provide Southern with fuel gas equivalent to the fuel gas Southern must provide ANR and Michigan Wisconsin to perform storage and transportation services for Southern for the benefit of that customer. The rate and fuel gas provisions of the storage service agreements are designed so that any changes in the charges and/or fuel gas the Commission authorizes ANR and Michigan Wisconsin to charge Southern flow through automatically to storage customers on a *pro rata* basis. No Southern charges or fuel gas are included in the storage service agreements.

Southern's charges for the transportation service to be provided under the storage transportation agreements would be based on the cost of service for the incremental facilities necessary to provide such transportation.

Southern states that it would be required to construct and operate certain additional pipeline facilities, in order to perform the transportation services provided for under the storage transportation agreements. An 1800 horsepower compressor and appurtenant facilities would be required at the Shadyside Delivery Point to enable Southern to transport gas to and from storage.

In order to accomodate the movement of storage transportation gas from Southern's South System to Southern's North System, Southern states that it would be required to install approximately 31 miles of 20-inch O.D. pipeline looping its existing line between Thomaston, Georgia, and Griffin, Georgia. An additional segment of 18-inch O.D. pipeline approximately 21 miles long would be required from Southern's South Atlanta Meter Station No. 1 north to the vicinity of the Austell tap on Southern's North Main Line. Southern states that a new route is required for this segment of pipeline because portions of Southern's existing lines between the South Atlanta Meter Station No. 1 and the Austell tap traverse densely concentrated residential areas making the looping of those lines impractical. The South Atlanta Meter Station No. 1 would be rebuilt in order to provide the increased capacity necessary to accommodate storage transportation volumes and a regulatory station would be installed at the intersection of the proposed South Atlanta-Austell pipeline and the existing North Main Line to ensure proper pressure in the north system.

Other changes, said to be required on the North System to enable Southern to transport storage transportation gas, include (i) the installation of a 1,200 horsepower compressor and appurtenant facilities at Southern's Bell Mills Compressor Station and (ii) certain modifications to existing piping and facilities at Southern's DeArmanville Compressor Station to permit the utilization of existing horsepower for the transportation service proposed herein.

Southern would also construct and operate approximately 44.7 miles of 12.75-inch O.D. pipeline extending from Southern's existing Rome Check Station No. 2 tap to Southern's existing Dalton No. 3 Meter Station. The new pipeline would loop Southern's existing Chattanooga Branch pipelines. To enable the redelivery of storage transportation volumes Southern would also (i) construct and operate as part of its Calhoun delivery point an additional meter station (to be known as Calhoun Station No. 2) and (ii) replace certain regulatory equipment at the existing Ringgold, Georgia, measuring station.

The extimated cost of constructing the proposed facilities is approximately $30,634,030.

Any person desiring to be heard or to make any protest with reference to said application should on or before August 6, 1979, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petition to intervenve in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to jurisdiction conferred upon the Federal Energy Regulatory Commission by Sections 7 and 15 of the Natuarl Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no petition to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that a grant of the certificate is required by the public convenience and necessity. If a petition for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Applicant to appear or be represented at the hearing.

Kenneth F. Plumb,

Secretary.

Southern Natural Gas Company

Customer Storage Service and Basis For Apportioning Monthly Charges To Customers

	Winter contract quantity (1)	Maximum daily withdrawal quantity (2)	Daily injection rate (3)
100 days service:			
South Georgia	70,800	708	331
Chattanooga	400,000	4,000	1,869
Atlanta Gas Light	5,150,000	51,000	24,065
Total 100 days service	5,620,800	56,208	26,265
50 days service:			
LaGrange	51,900	1,308	243
South Georgia	180,000	3,600	841
Atlanta	5,650,000	113,000	26,402
Total 50 days service	5,881,900	117,638	27,486
Total storage service	11,502,700	173,846	53,751

[FR Doc. 79-22830 Filed 7-20-79; 8:45 am]
BILLING CODE 6450-01-M

[Docket No. ER76-543]

Southwestern Public Service Co.; Compliance Filing

July 17, 1979.

Take notice that Southwestern Public Service Company on June 17, 1979 tendered for filing, in compliance with the Commission's order in the above-noted docket, its report of its compliance with the settlement agreement reached in this proceeding, including a schedule of the amounts refunded and the details of the computation.

Any person desiring to be heard or to protest said filing should file a protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8 and 1.10). All such protests should be filed on or before August 7, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,
Secretary.

[FR Doc. 79-22631 Filed 7-20-79; 8:45 am]
BILLING CODE 6450-01-M

[Docket No. ER79-274]

Southwestern Public Service Co.; Order Accepting Electric Rates for Filing, Suspending Proposed Rate Increase, Granting Interventions, and Establishing Procedures

Issued July 13, 1979.

On March 28, 1979, Southwestern Public Service Company (Southwestern) submitted for filing proposed revisions to the rate schedules for service to two full requirements and four partial requirements wholesale customers.[1] The proposed rates would increase revenues approximately $2,075,019 (34.49%) for the 12-month test period ending August 31, 1979.

The present full requirements rates include a 5,000 kW initial block rate, a lower rate for all additional billed kW, and a 60% ratchet. The present partial requirements rates include a flat charge for the first 500 kW of demand with a lower rate for all additional billed kW. The proposed demand rates for each class include a 500 kW initial block rate with a lower rate for all additional billed kW. Southwestern also proposes to increase the full requirements customers' ratchet to 85%.

The proposed revisions to the rate schedules for the full requirements customers decrease the energy charge from 5.16 mills/kWh to 4.0 mills/kWh and make no change in the fuel adjustment clause. No change is proposed for the energy or fuel adjustment components of the partial requirements rates.

The Secretary issued notice of the filing on March 30, 1979, with responses due on or before April 25, 1979. The Community Public Service Company, New Mexico Electric Service Company, Lea County Electric Cooperative, Cochran Power and Light Company, and the City of Brownfield filed timely petitions to intervene. Only the City of Brownfield raised specific issues, alleging an excessive increase in the demand charge and an excessive rate of return, and requesting a five month suspension.

Southwestern's revisions to the rate schedules have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or otherwise unlawful. Therefore, we will accept the revisions for filing and suspend them for five months from 60 days after the filing was completed, to become effective December 15, 1979, subject to refund. We shall institute an investigation to determine the reasonableness of the revisions. In an attempt to expedite the discovery process in this proceeding, we shall order the presiding administrative law judge to convene a prehearing conference, within 45 days of the date of this order, for the purpose of resolving any problems relating to the data requests of the Staff and the intervenors.

The Commission orders: (A) Southwestern's proposed revisions to the rate schedules designated in Attachment A are accepted for filing and suspended for five months, to become effective December 15, 1979, subject to refund.

(B) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Commission by subsection 402(a) of the Department of Energy Act and by the Federal Power Act, and pursuant to the Commission's Rules of Practice and Procedure and Regulations under the Federal Power Act (18 CFR Ch. I), a public hearing shall be held concerning the justness and reasonableness of Southwestern's proposed revisions to its rate schedules.

(C) Staff shall serve top sheets in this proceeding on or before October 15, 1979.

(D) A presiding administrative law judge, to be designated by the Chief Administrative Law Judge for that purpose, shall convene a prehearing conference in this proceeding, to be held within 45 days of the date of this order, in a hearing room of the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426. That conference shall be for the purpose of resolving any problems relating to the date requests of the staff and the intervenors. Within 10 days of the service of top sheets, the presiding administrative law judge shall convene a second prehearing conference. The presiding administrative law judge is authorized to establish procedural dates and to rule on all motions (except motions to consolidate or sever and motions to dismiss), as provided for in the Commission's Rules of Practice and Procedure.

(E) The Community Public Service

[1] On May 15, 1979, Southwestern completed the filing by submitting additional data. See Attachment A for rate schedule designations.

Company, New Mexico Electric Service Company, Lea County Electric Cooperative, Cochran Power and Light Company, and the City of Brownfield are permitted to intervene in this proceeding, subject to the Commission's Rules and Regulations: *Provided, however,* that participation by the intervenors shall be limited to matters set forth in their petitions to intervene; and *Provided, further,* that the admission of the intervenors shall not be construed as recognition by the Commission that they might be aggrieved by any order or orders of the Commission entered in this proceeding.

(F) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22632 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. CP79-390]

Tennessee Gas Pipeline Co., a Division of Tenneco Inc.; Application

July 13, 1979.

Take notice that on July 2, 1979, Tennessee Gas Pipeline Company, a Division of Tenneco Inc. (Tennessee), P.O. Box 2511, Houston, Texas 77001, filed in Docket No. CP79-390 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the transportation of up to 50,000 Mcf per day of natural gas for Orange and Rockland Utilities, Inc. (Orange and Rockland), all as more fully set forth in the application which is on file with the Commission and open for public inspection.

Tennessee states it would transport for Orange and Rockland during the period ending October 31, 1979, up to 50,000 Mcf per day of natural gas which Orange and Rockland has arranged to purchase from East Tennessee Natural Gas Company (East Tennessee). The gas proposed to be transported and delivered by Tennessee, the application indicates, would be used by Orange and Rockland solely to displace fuel oil it would otherwise use in its electric generating stations.

The subject gas would be made available to Tennessee by East Tennessee, for the account of Orange and Rockland, at Tennessee's existing Greenbriar Sales Meter Station delivery point to East Tennessee located in Robertson County, Tennessee. Tennessee would then deliver equivalent volumes, less transportation fuel and use volumes, to Orange and Rockland at the existing Pearl River Sales Meter Station delivery point located in Rockland County, New York.

The application states that assuming the proposed transportation commenced on July 1, 1979, Tennessee would transport up to 3,500,000 Mcf of gas for Orange and Rockland through October 31, 1979, based on a peak day transportation volume of 50,000 Mcf per day and approximately 28,455 Mcf on an average day. Orange and Rockland would pay a transportation rate to Tennessee of 34.80 cents per Mcf.

Tennessee states that the source of the natural gas to be sold is East Tennessee's general system supply which at present is surplus to its market requirements.

Any person desiring to be heard or to make any protest with reference to said application should on or before August 2, 1979, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petition to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no petition to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that a grant of the certificate is required by the public convenience and necessity. If a petition for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal, hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Tennessee to appear or be represented at the hearing.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22633 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. CP79-364]

Texas Eastern Transmission Co.; Application

July 16, 1979.

Take notice that on June 15, 1979, Texas Eastern Transmission Company (Texas Eastern), P.O. Box 2521, Houston, Texas 77001, filed in Docket No. CP79-364 an application pursuant to Section 7(c) of the Nutural Gas Act for a certificate of public convenience and necessity authorizing the transportation for Northern Natural Gas Company (Northern) up to 100,000 dekatherms equivalent of natural gas per day on a firm basis and up to 50,000 dekatherms equivalent of natural gas on an interruptible basis and authorizing the construction and operation of certain facilities for receipt of such gas, all as more fully set forth in the application on file with the Commission and open to public inspection.

Texas Eastern states that Northern has contracted for the purchase of certain quanitites of gas produced in the High Island Area, offshore Texas, and has requested that Transcontinental Gas Pipe Line Corporation (Transco), Houston Pipe Line Company (Houston) and Texas Eastern transport such gas. Texas Eastern would receive up to the stated quantities of natural gas from Transco at their existing point of interconnection located at Ragely, Louisiana, on an interim basis and upon completion of the construction of the facilities prosposed herein, Texas Eastern would receive such gas at Starks, Louisiana. Texas Eastern would then transport and redeliver such gas, less quantities for fuel and loss, to Houston for Northern's account, at the point of interconnection between Texas Eastern and Houston at Mont Belvieu, Texas. Texas Eastern indicates that Transco would redeliver the gas to Northern.

Texas Eastern would charge Northern a monthly charge of $678,596 for the firm transportation service and a rate of 22.31 cents per dekatherm delivered in excess of the demand quantity of 100,000 dekatherms per day. Further, Texas Eastern would retain, for fuel and loss, a daily quantity equal to 3 percent of the amount transported.

Texas Eastern proposes to construct and operate certain tap and metering facilities at Starks, Louisiana, for the receipt of gas from Transco for the account of Northern. The total cost of these facilities is estimated to be $430,000 and Northern would reimburse Texas Eastern for the cost of the construction of such facilities; however, operation of such facilities would be at Texas Eastern's expense.

Any person desiring to be heard or to make any protest with reference to said application should on or before August 7, 1979, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petition to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to jurisdiction conferred upon the Federal Energy Regulatory Commission by Sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no petition to intervene is file within the time required herein, if the Commission on its own review of the matter finds that a grant of the certificate is for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Texas Eastern to appear or be represented at the hearing.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22634 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. CP79-383]

Texas Eastern Transmission Corp.; Application

July 16, 1979.

Take notice that on June 25, 1979, Texas Eastern Transmission Corporation (Texas Eastern), P.O. Box 2521, Houston, Texas 77001, filed in Docket No. CP79-383 an application pursuant to Section 7(b) of the Natural Gas Act for permission and approval to abandon operation in interstate commerce of certain existing natural gas pipeline in Texas for conversion to common carrier products service, all as more fully set forth in the application which is on file with the Commission and open for public inspection.

Texas Eastern proposes to abandon operation in interstate commerce of 18.3 miles of 8-inch Alco-Mag Line No. 8-B and 12.74 miles of 8-inch Aldine Line No. 8-B-1, an extension of the Alco-Mag-Aldine Line, all located in Harris County, Texas, used for the transportation of natural gas. Texas Eastern states that the Alco-Mag-Aldine pipeline would be disconnected from its interstate gas transmission system and transferred to the Texas Eastern Products Pipeline Division for use in common carrier products transportation service.

In order to achieve optimum utilization of its gas system and in conjunction with its common carrier products transportation service, Texas Eastern asserts, it has determined that the 8-inch Alco-Mag-Aldine pipeline could be abandoned from gas transmission service without impairing its current or future gas system operations. Texas Eastern further states that the gas deliveries from the Alco-Magnolia Oil Field, approximately 757 Mcf per day, would not be abandoned. The transportation service would be rendered by Houston Pipe Line Company.

Texas Eastern states that upon the transfer of the Alco-Mag-Aldine line to Texas Eastern Products Pipeline Division for common carrier products transportation service the net depreciated cost of such facilities would be removed from Texas Eastern's gas plant in service accounts and transferred to the Products Pipeline Division. In addition to the transfer of the cost of the Alco-Mag-Aldine line to the Products Pipeline Division, the cost of conversion of said pipeline to products service and the cost of connection to Houston Pipe Line Company would be borne by the Products Pipeline Division.

The total gross amount of investment attributable to facilities to be abandoned is $1,209,000 and the removal from Texas Eastern's gas plant in service account would amount to a reduction in Texas Eastern's rate base of $274,100.

The application indicates that there would be no affect on the level of service to existing customers nor would there be any sacrifice of existing gas supplies as a result of the proposed abandonment. The Alco-Mag-Aldine line is said to traverse an area of diminishing gas production, and abandonment would not affect Texas Easterns ability to secure gas supplies for its system.

Any person desiring to be heard or to make any protest with reference to said application should on or before August 7, 1979, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petition to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to jurisdiction conferred upon the Federal Energy Regulatory Commission by Sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no petition to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that permission and approval for the proposed abandonment are required by the public convenience and necessity. If a petition for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Texas Eastern to appear or be represented at the hearing.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22635 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

Texas Railroad Commission, Oil and Gas Division, et al.; Determinations by Jurisdictional Agencies Under the Natural Gas Policy Act of 1978

July 12, 1979.

The Federal Energy Regulatory Commission received notices from the jurisdictional agencies listed below of determinations pursuant to 18 CFR 274.104 and applicable to the indicated wells pursuant to the Natural Gas Policy Act of 1978.

Texas Railroad Commission, Oil and Gas Division

1. Control Number (FERC/State)
2. API well number
3. Section of NGPA
4. Operator
5. Well name
6. Field or OCS area name
7. County, State or Block No.
8. Estimated annual volume
9. Date received at FERC
10. Purchaser(s)

1. 79–10441
2. 42–503–32665
3. 103
4. Beren Corporation
5. Reeves #4
6. Reeves (Marble Falls)
7. Young
8. 130.0 million cubic feet
9. June 22, 1979
10.

1. 79–10442
2. 42–195–30298
3. 103
4. Scarth Petroleum Inc
5. #1 Cline Well 71380
6. Hansford (North Tonkawa)
7. Hansford, TX
8. 65.0 million cubic feet
9. June 22, 1979
10. Panhandle Eastern Pipeline Co, Northern Natural Gas Co

1. 79–10443
2. 42–195–30292
3. 103
4. Scarth Petroleum Inc
5. No 2 Hill 71634
6. Hansford (North Tonkawa) Field
7. Hansford, TX
8. 1.3 million cubic feet
9. June 22, 1979
10. Panhandle Eastern Pipeline Co

1. 79–10444
2. 42–295–30421
3. 103
4. Scarth Petroleum Inc
5. No 601–1 Piper Well 77299
6. Bradford (Cleveland) Field
7. Lipscomb, TX
8. 55.0 million cubic feet
9. June 22, 1979
10. Transwestern Pipeline Company

1. 79–10445
2. 42–469–31327
3. 102
4. Bay Rock Corporation
5. Robert L Massey No 1
6. Koontz NE (5950)
7. Victoria
8. 360.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79–10446
2. 42–497–00000
3. 103
4. Taylor Operating Company
5. R H Nobles #1 (18771)
6. R H Nobles (6000 Congl)
7. Wise, TX
8. 28.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipe Co of Amer

1. 79–10447
2. 42–237–00000
3. 103
4. Taylor Operating Company
5. Elzie Lewis #1 (18947)
6. Cundiff (Atoka 5660)
7. Jack, TX
8. 150.0 million cubic feet
9. June 22, 1979
10. Cities Service Company

1. 79–10448
2. 42–497–00000
3. 103
4. Taylor Operating Company
5. Thomas Hodges No 2 (18753)
6. Wise County Regular
7. Wise, TX
8. 8.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipe Co of Amer

1. 79–10449
2. 42–297–00000
3. 102
4. Rocanville Corporation
5. Schulz #1
6. Schulz (Edwards) Field
7. Live Oak, TX
8. 365.0 million cubic feet
9. June 22, 1979
10.

1. 79–10450
2. 42–297–00000
3. 102
4. Rocanville Corporation
5. J Gerald Schulz #1—RRC #74657
6. Schulz (Edwards) Field
7. Live Oak, TX
8. 365.0 million cubic feet
9. June 22, 1979
10.

1. 79–10451
2. 42–239–00000
3. 102
4. Arledge Petroleum Corporation
5. Kountze-Couch Well No 1
6. Mauritz NE (5300)
7. Jackson, TX
8. 146.0 million cubic feet
9. June 22, 1979
10. Texas Eastern Transmission Corp

1. 79–10452
2. 42–123–30798
3. 102
4. William Herbert Hunt Trust Estate
5. Harold Heyer 1–T 05533
6. Arneckeville
7. Dewitt, TX
8. 24.0 million cubic feet
9. June 22, 1979
10. Texas Eastern Transmission Corp

1. 79–10453
2. 42–123–30883
3. 102
4. D H Hunt
5. Ideus Gas Unit Well #1 79948
6. Arneckeville (Frio 2900)
7. Dewitt, TX
8. 370.0 million cubic feet
9. June 22, 1979
10. Texas Eastern Transmission Corp

1. 79–10454
2. 42–079–30861
3. 103
4. Sun Oil Company (Delaware)
5. League 91 Project No 124
6. Slaughter (Slaughter Plant)
7. Cochran, TX
8. 4.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company, Amoco Production Co

1. 79–10455
2. 42–079–30859
3. 103
4. Sun Oil Company (Delaware)
5. League 91 Project No 123
6. Slaughter (Slaughter Plant)
7. Cochran, TX
8. 6.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company, Amoco Production Co

1. 79–10456
2. 42–079–30496
3. 103
4. Sun Oil Company (Delaware)
5. League 91 Project No 121
6. Slaughter (Slaughter Plant)
7. Cochran, TX
8. 1.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company, Amoco Production Co

1. 79–10457
2. 42–079–30862
3. 103
4. Sun Oil Company (Delaware)
5. League 91 Project No 127
6. Slaughter (Slaughter Plant)
7. Cochran, TX
8. 7.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company, Amoco Production Co

1. 79–10458
2. 42–135–32198
3. 103
4. Sun Oil Company (Delaware)
5. Foster-Johnson Unit No 716
6. Foster
7. Ector, TX
8. 1.0 million cubic feet
9. June 22, 1979
10. Odessa Natural Corp

1. 79–10459
2. 42–135–32183
3. 103
4. Sun Oil Company (Delaware)
5. Foster-Johnson Unit No 716
6. Foster
7. Ector, TX
8. 1.0 million cubic feet
9. June 22, 1979
10. Odessa Natural Corp

1. 79-10460
2. 42-399-31019
3. 103
4. Wes-Tex Drilling Company
5. Mozelle Wilbanks A No 1
6. Ballinger (Gardner)
7. Runnels, TX
8. 5.5 million cubic feet
9. June 22, 1979
10. Union Texas Petroleum

1. 79-10461
2. 42-399-30978
3. 103
4. Wes-Tex Drilling Company
5. J J Wessels No 3
6. Winters S W (Gardner Lime)
7. Runnels, TX
8. 9.1 million cubic feet
9. June 22, 1979
10. Union Texas Petroleum

1. 79-10462
2. 42-399-31097
3. 103
4. Wes-Tex Drilling Company
5. J J Wessels No 4
6. Winters S W (Gardner Lime)
7. Runnels, TX
8. 9.1 million cubic feet
9. June 22, 1979
10. Union Texas Petroleum

1. 79-10463
2. 42-399-31114
3. 103
4. Wes-Tex Drilling Company
5. J J Wessels No 5
6. Winters S W (Gardner Lime)
7. Runnels, TX
8. 9.1 million cubic feet
9. June 22, 1979
10. Union Texas Petroleum

1. 79-10464
2. 42-123-30836
3. 102
4. William Herbert Hunt Trust Estate
5. Harold Heyer No 2-T 05533
6. Arneckeville (Yegua 4910)
7. Dewitt, TX
8. 16.0 million cubic feet
9. June 22, 1979
10. Texas Eastern Transmission Corp

1. 79-10465
2. 42-371-32433
3. 107
4. Gulf Oil Corp
5. Ivy B Weatherby A No 2
6. Rojo Caballos South (Devonian)
7. Pecos, TX
8. 3,200.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10466
2. 42-233-00000
3. 108
4. Sohio Natural Resources Co
5. Johnson #2 well
6. West Panhandle
7. Hutchinson, TX
8. 20.8 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co.

1. 79-10467
2. 42-233-00000
3. 108
4. Sohio Natural Resources Co
5. Whittenberg #2 well
6. West Panhandle
7. Hutchinson, TX
8. 12.4 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co.

1. 79-10468
2. 42-233-00000
3. 108
4. Sohio Natural Resources Co
5. Whittenberg #5 well
6. West Panhandle
7. Hutchinson, TX
8. 4.4 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co.

1. 79-10469
2. 42-233-00000
3. 108
4. Sohio Natural Resources Co
5. Sanford #3 well
6. West Panhandle
7. Hutchinson, TX
8. 8.4 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co.

1. 79-10470
2. 42-233-00000
3. 108
4. Sohio Natural Resources Co
5. Whittenberg #3 well
6. West Panhandle
7. Hutchinson, TX
8. 4.7 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co.

1. 79-10471
2. 42-227-31562
3. 103
4. Wes-Tex Drilling Company
5. J L Jones Heirs No 3
6. Vincent (Clear Fork Lower).
7. Howard, TX
8. 9.1 million cubic feet
9. June 22, 1979
10. Getty Oil Company

1. 79-10472
2. 42-135-32695
3. 103
4. Phillips Petroleum Company
5. Cowden—U No. 4
6. Donnelly (San Andres)
7. Ector, TX
8. 6.9 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10473
2. 42-355-31174
3. 103
4. American Petrofina Company of Texas
5. W C Rivers No 6
6. Agua Dulce (6550)
7. Nueces, TX
8. 25.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Co.

1. 79-10474
2. 42-295-30576
3. 102
4. Lear Petroleum Corporation
5. Scott No. 1
6. Lear (Morrow Upper)
7. Lipscomb, TX
8. 365.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company, Ruel Gas Co.

1. 79-10475
2. 42-295-00000
3. 102
4. Lear Petroleum Corporation
5. Ingle No. 2
6. Lear (Morrow Upper)
7. Lipscomb, TX
8. 55.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company, Ruel Gas Co.

1. 79-10476
2. 42-235-30784
3. 103
4. Energy Reserves Group, Inc.
5. Ela C Sugg 68 #3
6. Spraberry Trend Area
7. Irion, TX
8. 39.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co.

1. 79-10477
2. 42-235-30761
3. 103
4. Energy Reserves Group, Inc.
5. Ela C Sugg 55 #1
6. Spraberry Trend Area
7. Irion, TX
8. 11.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co.

1. 79-10478
2. 42-235-30766
3. 103
4. Energy Reserves Group, Inc.
5. Ela C Sugg 53 #1
6. Spraberry Trend Area
7. Irion, TX
8. 4332.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co.

1. 79-10479
2. 42-235-30783
3. 103
4. Energy Reserves Group, Inc.
5. Ela C Sugg 59A #3
6. Spraberry Trend Area
7. Irion, TX
8. 14.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co.

1. 79-10480
2. 42-235-30765
3. 103
4. Energy Reserves Group, Inc.
5. Ela C Sugg 73 #1
6. Spraberry Trend Area
7. Irion, TX
8. 21.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co.

1. 79-10481
2. 42-235-30791
3. 103
4. Energy Reserves Group, Inc.
5. Ela C Sugg 68 #4
6. Spraberry Trend Area
7. Irion, TX
8. 44.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co.

1. 79-10482
2. 42-235-31161
3. 103
4. Energy Reserves Group, Inc.
5. Ela C Sugg 55 #2
6. Spraberry Trend Area
7. Irion, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co.

1. 79-10483
2. 42-081-30688
3. 103
4. Enrich Oil Corporation
5. O B Jacobs 313 No 1-313
6. Bloodworth N (Canyon 5650)
7. Coke, TX
8. 255.5 million cubic feet
9. June 22, 1979
10. Sun Gas Company

1. 79-10484
2. 42-081-30689
3. 103
4. Enrich Oil Corporation
5. O B Jacobs No 1
6. Bloodworth N (Canyon 5650)
7. Coke, TX
8. 255.5 million cubic feet
9. June 22, 1979
10. Sun Gas Company

1. 79-10485
2. 42-355-30862
3. 103
4. Pennzoil Producing Company
5. C. P. Talbert No 16-L
6. Agua Dulce
7. Nueces, TX
8. 350.0 million cubic feet
9. June 22, 1979
10. United Gas Pipeline Co.

1. 79-10486
2. 42-211-30979
3. 103
4. Donald C Slawson
5. Yokley Unit #1 RRC #77693
6. Canadian West Morrow Upper
7. Hemphill Co, TX
8. 425.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10487
2. 42-211-30870
3. 103
4. Donald C Slawson
5. Mitchell A Unit RRC #74404
6. Canadian West Morrow Upper
7. Hemphill, TX
8. 18.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10488
2. 42-237-32144
3. 103
4. David Albert Oil & Gas
5. Cranford 2A
6. Jack County Regular—Gas
7. Jack, TX
8. 40.0 million cubic feet
9. June 22, 1979
10. Cities Service Co

1. 79-10489
2. 42-195-30592
3. 103
4. Horizon Oil & Gas Co of Texas
5. Oloughlin 1-19 73139
6. Hansford Upper Morrow
7. Hansford, TX
8. 60.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10490
2. 42-357-30801
3. 103
4. Horizon Oil & Gas of Texas
5. Greever 1-75 75332
6. Hansford Upper Morrow
7. Ochiltree, TX
8. 12.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10491
2. 42-195-30646
3. 103
4. Horizon Oil & Gas Co of Texas
5. Schiff 1-31 78040
6. Hansford Lower Morrow
7. Hansford, TX
8. 400.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co of America

1. 79-10492
2. 42-235-30798
3. 103
4. Energy Reserves Group Inc
5. Ela C Sugg D #3
6. Spraberry Trend Area
7. Irion, TX
8. 21.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10493
2. 42-235-30792
3. 103
4. Energy Reserves Group Inc
5. Ela C Sugg 59 #2
6. Spraberry Trend Area
7. Irion, TX
8. 17.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10494
2. 42-211-30995
3. 103
4. McCulloch Oil Corp of Texas
5. Studer No 4
6. Humphreys-Douglas
7. Hemphill, TX
8. 66.0 million cubic feet
9. June 22, 1979
10. Arkansas Louisisana Gas Company

1. 79-10495
2. 42-211-30989
3. 103
4. McCulloch Oil Corp of Texas
5. Mathers Ranch No 35
6. Humphreys-Douglas
7. Hemphill, TX
8. 384.0 million cubic feet
9. June 22, 1979
10. Arkansas Lousisana Gas Company

1. 79-10496
2. 42-211-30942
3. 103
4. McCulloch Oil Corp of Texas
5. Mathers Ranch No 31
6. Humphreys-Douglas
7. Hemphill, TX
8. 38.0 million cubic feet
9. June 22, 1979
10. Arkansas Louisiana Gas Co

1. 79-10497
2. 42-365-00000
3. 108
4. Erso Inc
5. Carthage Unit 6-T
6. Carthage
7. Panola, TX
8. 11.8 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipe Line Co

1. 79-10498
2. 42-365-00000
3. 108
4. Erso Inc
5. Louis Werner #2
6. Carthage
7. Panola, TX
8. 10.4 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipe Line Co

1. 79-10499
2. 42-211-30945
3. 103
4. McCulloch Oil Corp of Texas
5. Mathers Ranch No 30
6. Humphreys-Douglas
7. Hemphill, TX
8. 384.0 million cubic feet
9. June 22, 1979
10. Arkansas Louisiana Gas Co

1. 79-10500
2. 42-211-30996
3. 103
4. McCulloch Oil Corp of Texas
5. Mathers Ranch No 29
6. Humphreys-Douglas
7. Hemphill, TX
8. 168.0 million cubic feet
9. June 22, 1979
10. Arkansas Louisiana Gas Company

1. 79-10501
2. 42-211-30992
3. 103
4. McCulloch Oil Corp of Texas
5. Mathers Ranch No 28
6. Humphreys-Douglas
7. Hemphill, TX
8. 54.0 million cubic feet
9. June 22, 1979
10. Arkansas Louisiana Gas Co

1. 79-10502
2. 42-211-30946
3. 103
4. McCulloch Oil Corp of Texas
5. Mathers Ranch No 27
6. Humphreys-Douglas
7. Hemphill, TX
8. 278.0 million cubic feet
9. June 22, 1979
10. Arkansas Louisiana Gas Company

1. 79-10503
2. 42-211-30941
3. 103
4. McCulloch Oil Corp of Texas
5. Mathers Ranch No 25
6. Humphreys-Douglas
7. Hemphill, TX
8. 385.0 million cubic feet
9. June 22, 1979
10. Arkansas Louisiana Gas Company

1. 79-10504

2. 42-211-30876
3. 103
4. McCulloch Oil Corp of Texas
5. Mathers Ranch No 24
6. Humphreys-Douglas
7. Hemphill, TX
8. 396.0 million cubic feet
9. June 22, 1979
10. Arkansas Louisiana Gas Co

1. 79-10505
2. 42-211-30713
3. 103
4. McCulloch Oil Corp of Texas
5. Mathers Ranch No 23
6. Humphreys-Douglas
7. Hemphill, TX
8. 258.0 million cubic feet
9. June 22, 1979
10. Arkansas Louisiana Gas Company

1. 79-10506
2. 42-219-32499
3. 103
4. Amoco Production Company
5. West RKM Unit No 208
6. Slaughter
7. Hockley, TX
8. 10.2 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10507
2. 42-219-32496
3. 103
4. Amoco Production Company
5. West RKM Unit No 212
6. Slaughter
7. Hockley, TX
8. 17.5 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10508
2. 42-219-32504
3. 103
4. Amoco Production Company
5. West RKM Unit No 199
6. Slaughter
7. Hockley, TX
8. 9.1 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10509
2. 42-219-32502
3. 103
4. Amoco Production Company
5. West RKM Unit No 206
6. Slaughter
7. Hockley, TX
8. 7.3 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10510
2. 42-219-32509
3. 103
4. Amoco Production Company
5. West RKM Unit Well No 245
6. Slaughter
7. Hockley, TX
8. 12.8 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10511
2. 42-219-32508
3. 103
4. Amoco Production Company
5. West RKM Unit Well No 247
6. Slaughter
7. Hockley, TX
8. 5.1 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10512
2. 42-219-32602
3. 103
4. Amoco Production Company
5. East RKM Unit No 61
6. Slaughter
7. Hockley, TX
8. 8.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10513
2. 42-103-31479
3. 103
4. Gulf Oil Corp
5. J T McElroy Cons No 957
6. McElroy
7. Crane, TX
8. .7 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10514
2. 42-427-30881
3. 103
4. Sun Oil Company (Delaware)
5. G G Villarreal B Unit 14 Well #2-U
6. Garcia (Stray 3470)
7. Starr, TX
8. 7.0 million cubic feet
9. June 22, 1979
10.

1. 79-10515
2. 42-427-30881
3. 103
4. Sun Oil Company (Delaware)
5. G G Villarreal B Unit 14 Well #2-L
6. Garcia (3470 Stray)
7. Starr, TX
8. 4.0 million cubic feet
9. June 22, 1979
10. Transcontinental Gas Pipe Line Corp

1. 79-10516
2. 42-219-32487
3. 103
4. Amoco Production Company
5. West RKM Unit Well No 225
6. Slaughter
7. Hockley, TX
8. 27.4 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10517
2. 42-219-32510
3. 103
4. Amoco Production Company
5. West RKM Unit Well No 246
6. Slaughter
7. Hockley, TX
8. 12.4 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10518
2. 42-219-32578
3. 103
4. Amoco Production Company
5. East RKM Unit No 48
6. Slaughter
7. Hockley, TX
8. 8.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10519
2. 42-219-32500
3. 103
4. Amoco Production Company
5. West RKM Unit No 215
6. Slaughter
7. Hockley, TX
8. 15.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10520
2. 42-219-32590
3. 103
4. Amoco Production Company
5. East RKM Unit No 70
6. Slaughter
7. Hockley, TX
8. 8.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10521
2. 42-219-32495
3. 103
4. Amoco Production Company
5. West RKM Unit No 227
6. Slaughter
7. Hockley, TX
8. 15.4 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10522A
2. 42-219-32494
3. 103
4. Amoco Production Company
5. West RKM Unit Well No 196
6. Slaughter
7. Hockley, TX
8. 15.4 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10522B
2. 42-065-00000
3. 108
4. Dorchester Gas Producing Co
5. Burgin No 1 (24335)
6. West Panhandle
7. Carson, TX
8. 5.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10523
2. 42-179-00000
3. 108
4. Dorchester Gas Producing Co
5. Beavers No 1 (24332)
6. West Panhandle
7. Gray, TX
8. 5.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10524
2. 42-065-00000
3. 108
4. Dorchester Gas Producing Co
5. Bednorz No 1 (24323)
6. West Panhandle
7. Carson, TX
8. 12.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10525
2. 42-065-00000

3. 108
4. Dorchester Gas Producing Co
5. Dowd No 1 (24341)
6. West Panhandle
7. Carson TX
8. 9.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10526
2. 42-295-30540
3. 102
4. Lear Petroleum Corporation
5. Pitts No 1
6. Lear (Morrow Upper)
7. Lipscomb TX
8. 730.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company, Rael Gas Co

1. 79-10527
2. 42-295-30557
3. 102
4. Lear Petroleum Corporation
5. Ingle No 1
6. Lear (Morrow Upper)
7. Lipscomb TX
8. 55.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co, Rael Gas Co

1. 79-10528
2. 42-295-00000
3. 102
4. Lear Petroleum Corporation
5. Walton No 1
6. Lear (Morrow Upper)
7. Lipscomb TX
8. 73.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co, Rael Gas Co

1. 79-10529
2. 42-179-00000
3. 108
4. Dorchester Gas Producing Co
5. Osborne No 2 (24377)
6. West Panhandle
7. Gray TX
8. 17.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10530
2. 42-065-00000
3. 108
4. Dorchester Gas Producing Co
5. Kuykendall (24362)
6. West Panhandle
7. Carson TX
8. 7.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10531
2. 42-469-00000
3. 108
4. Monsanto Company
5. Leona Reeves No 4
6. Cologne (1400)
7. Victoria TX
8. 10.3 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79-10532
2. 42-469-00000
3. 108
4. Monsanto Company
5. Leona Reeves No 7
6. Cologne (4800)
7. Victoria TX
8. .0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79-10533
2. 42-179-00000
3. 108
4. Dorchester Gas Producing Co
5. Evans No 1 (24345)
6. West Panhandle
7. Gray TX
8. 80.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10705
2. 42-003-30729
3. 103
4. Exxon Corporation
5. Means SA Unit #3558
6. Means
7. Andrews TX
8. 1.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co

1. 79-10706
2. 42-065-00000
3. 108
4. Dorchester Gas Producing Co
5. McConnell No 7 (24370)
6. West Panhandle
7. Carson TX
8. 18.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10707
2. 42-179-00000
3. 108
4. Dorchester Gas Producing Co
5. Pinnell No 1 (24381)
6. West Panhandle
7. Gray TX
8. 31.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10708
2. 42-497-0000
3. 103
4. V L Wolsey
5. Carl H Watson No 1 RRC 18907
6. Park Springs Congl
7. Wise TX
8. 65.0 million cubic feet
9. June 22, 1979
10. Cities Service Co

1. 79-10709
2. 42-317-31635
3. 103
4. Hytech Energy Corporation
5. Mabee E No 1
6. Spraberry (Trend Area)
7. Martin TX
8. 2.6 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10710
2. 42-317-31921
3. 103
4. Hytech Energy Corporation
5. Mabee E No 2
6. Spraberry (Trend Area)
7. Martin TX
8. 2.6 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10711
2. 42-235-31316
3. 103
4. Hytech Energy Corporation
5. Childress No 2
6. ELA Sugg (Wolfcamp)
7. Irion TX
8. 68.2 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10712
2. 42-235-31279
3. 103
4. Hytech Energy Corporation
5. Childress No 1
6. Ela Sugg (Wolfcamp)
7. Irion TX
8. 35.7 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10713
2. 42-235-30754
3. 103
4. Hytech Energy Corporation
5. Rocker B-110 No 1
6. Ela Sugg (Wolfcamp)
7. Iron TX
8. 19.5 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10714
2. 42-235-31258
3. 103
4. Hytech Energy Corporation
5. Rocker B-106 No 1
6. Ela Sugg (Wolfcamp)
7. Irion TX
8. 10.6 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10715
2. 42-247-30806
3. 102 103
4. Exxon Corporation
5. Mrs A M K Bass Well No 35-T 79657
6. Kelsey Deep (7990)
7. Jim Hogg TX
8. 300.0 million cubic feet
9. June 22, 1979
10. Trunkline Gas Company

1. 79-10716
2. 42-003-31183
3. 103
4. Exxon Corporation
5. Means SA Unit #1566
6. Means
7. Andrews TX
8. 1.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co

1. 79-10718
2. 42-003-31693
3. 103
4. Exxon Corporation
5. Means SA Unit #1264
6. Means
7. Andrews TX
8. 3.0 million cubic feet
9. June 22, 1979
10. Phillips Petroeum Co

1. 79-10720
2. 42-165-31438

3. 103
4. Exxon Corporation
5. Robertson (Clfrk) Unit #5602
6. Robertson N (Clearfork 7100)
7. Gaines TX
8. 11.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co

1. 79-10722
2. 42-165-31306
3. 103
4. Exxon Corporation
5. Robertson (Clfk) Unit Well #9902
6. Robertson N (Clearfork 7100)
7. Gaines TX
8. 9.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co

1. 79-10724
2. 42-393-00000
3. 103
4. Pioneer Production Corporation
5. Morrison #1-12 #77530
6. Carrie-Kellebrew (Morrow)
7. Roberts TX
8. 3517.0 million cubic feet
9. June 22, 1979
10. Pioneer Natrual Gas Company

1. 79-10717
2. 42-261-30411
3. 102 103
4. Exxon Corporation
5. Sarita Fld O & G Unit #138-D 79267
6. Sarita (17-A W)
7. Kenedy TX
8. 165.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co

1. 79-10719
2. 42-165-30599
3. 103
4. Exxon Corporation
5. Robertson (Clfrk) Unit #5902
6. Robertson N (Clearfork 7100)
7. Gaines TX
8. 20.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co

1. 79-10721
2. 42-165-31285
3. 103
4. Exxon Corporation
5. Robertson (Clfk) Unit Well No 9802
6. Robertson N (Clearfork) 7100
7. Gaines TX
8. 4.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co

1. 79-10723
2. 42-505-31037
3. 102
4. Pennzoil Producing Company
5. Jennings No 38
6. Jennings W
7. Zapata TX
8. .0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Company of AME

1. 79-10725
2. 42-295-00000
3. 103
4. Dorchester Exploration Inc
5. Schoenhals No 1
6. Horsecreek NW
7. Lipscomb TX
8. .0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10726
2. 42-295-30526
3. 103
4. Dorchester Exploration Inc
5. C L Unit No 1-A
6. Horsecreek NW
7. Lipscomb TX
8. .0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10727
2. 42-295-30525
3. 103
4. Dorchester Exploration Inc
5. Kelln 205 No 1
6. Horsecreek NW
7. Lipscomb TX
8. .0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10728
2. 42-295-30556
3. 103
4. Dorchester Exploration Inc
5. Kelln 206 No 1
6. Horsecreek NW
7. Lipscomb TX
8. .0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10729
2. 42-165-00000
3. 103
4. Wood McShane & Thams
5. Simpson #1—RRC #75069
6. Block A-34 (Yates)
7. Gaines TX
8. .6 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10730
2. 42-165-00000
3. 103
4. Wood McShane & Thams
5. Elam #1—RRC #75067
6. Block A-34 (Yates)
7. Gaines TX
8. 3.4 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10731
2. 42-165-00000
3. 103
4. Wood McShane & Thams
5. Mayo B #1—RRC #75066
6. Block A-34 (Yates)
7. Gaines TX
8. .4 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10732
2. 42-165-00000
3. 103
4. Wood McShane & Thams
5. Mayo A #1—RRC #75065
6. Block A-34 (Yates)
7. Gaines TX
8. 3.5 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10733
2. 42-165-00000
3. 103
4. Wood McShane & Thams
5. Alexander #1—RRC #75046
6. Block A-34 (Yates)
7. Gaines & Andrews TX
8. 3.9 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10734
2. 42-247-30802
3. 102 103
4. Exxon Corporation
5. Mrs A M K Bass B Well #15-F 77741
6. Kelsey Deep (Zone 19-A Seg 8)
7. Jim Hogg TX
8. 100.0 million cubic feet
9. June 22, 1979
10. Trunkline Gas Company

1. 79-10735
2. 42-367-30855
3. 102
4. Mitchell Energy Corporation
5. N G Watkins #1 74683
6. Lake Mineral Wells (4000' Congl)
7. Parker TX
8. .0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co of America

1. 79-10736
2. 42-165-30644
3. 103
4. Exxon Corporation
5. Robertson (clfrk) Unit #6302
6. Robertson N (Clearfork)
7. Gaines TX
8. 26.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10737
2. 42-211-30956
3. 103
4. Philcon Development Co
5. Temple #1
6. Mendota NW (Granite Wash)
7. Hemphill TX
8. 48.0 million cubic feet
9. June 22, 1979
10. Diamond Shamrock Corporation

1. 79-10738
2. 42-389-30923
3. 103
4. Gulf Oil Corporation
5. R Cleveland et al Well #9
6. Worsham, Bayer (Penn.)
7. Reeves TX
8. 750.0 million cubic feet
9. June 22, 1979
10. Transwestern Pipeline Co

1. 79-10739
2. 42-475-31752
3. 103
4. Gulf Oil Corporation
5. E W Estes Well #246
6. Estes Block 34 (Penn.)
7. Ward TX
8. 8.0 million cubic feet
9. June 22, 1979
10. Cabot Corporation

1. 79-10740
2. 42-473-30298
3. 103
4. Exxon Corporation

5. Katy Gas Fld Consolidated Ut Well 4
6. Katy (I-A)
7. Waller TX
8. 3650.0 million cubic feet
9. June 22, 1979
10. United Texas Transmission Co, Lone Star Gas Co

1. 79-10741
2. 42-339-30410
3. 103
4. Exxon Corporation
5. Conroe Field Unit Well #110
6. Conroe Field
7. Montgomery TX
8. 110.0 million cubic feet
9. June 22, 1979
10. Moran Utilities Company

1. 79-10742
2. 42-339-30407
3. 103
4. Exxon Corporation
5. Conroe Field Unit Well #310
6. Conroe Field
7. Montgomery TX
8. 180.0 million cubic feet
9. June 22, 1979
10. Moran Utilities Company

1. 79-10743
2. 42-211-31003
3. 103
4. Courson Oil & Gas Inc
5. Knighton A #1-90
6. Gem-Hemphill (Tonkawa)
7. Hemphill TX
8. 200.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10745
2. 42-383-31292
3. 103
4. Hanley Company
5. University 58-18B Well #1 (07718)
6. Spraberry (Trend Area)
7. Reagan TX
8. 5.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10746
2. 42-473-30082
3. 103
4. Exxon Corporation
5. Katy Gas Fld Consolidated Ut Well 62
6. Katy (IV)
7. Waller TX
8. 2190.0 million cubic feet
9. June 22, 1979
10. United Texas Transmission Co, Lone Star Gas Co

1. 79-10747
2. 42-473-30081
3. 103
4. Exxon Corporation
5. Katy Gas Fld Consolidated Ut Well 5
6. Katy (Cockfield Upper B)
7. Waller TX
8. 2190.0 million cubic feet
9. June 22, 1979
10. United Texas Transmission Co, Lone Star Gas Co

1. 79-10748
2. 42-473-30081
3. 103
4. Exxon Corporation
5. Katy Gas Fld Consolidated Ut Well 53
6. Katy (IV)
7. Waller TX
8. 1825.0 million cubic feet
9. June 22, 1979
10. United Texas Transmission Co, Lone Star Gas Co

1. 79-10749
2. 42-473-30081
3. 103
4. Exxon Corporation
5. Katy Gas Fld Consolidated Ut Well 5
6. Katy (III-A)
7. Waller TX
8. 1095.0 million cubic feet
9. June 22, 1979
10. United Texas Transmission Co, Lone Star Gas Co

1. 79-10750
2. 42-473-30082
3. 103
4. Exxon Corporation
5. Katy Gas Fld Consolidated Ut Well 62
6. Katy (II-B)
7. Waller TX
8. 6570.0 million cubic feet
9. June 22, 1979
10. United Texas Transmission Co, Lone Star Gas Co

1. 79-10751
2. 42-473-30082
3. 103
4. Exxon Corporation
5. Katy Gas Fld Consolidated Ut Well 6
6. Katy (III-A)
7. Waller TX
8. 2555.0 million cubic feet
9. June 22, 1979
10. United Texas Transmission Co, Lone Star Gas Co

1. 79-10752
2. 42-467-30383
3. 103
4. Exxon Corporation
5. R S Blake Well #23
6. Van
7. Van Zandt TX
8. 20.0 million cubic feet
9. June 22, 1979
10. United Gas Pipe Line Company

1. 79-10753
2. 42-339-30397
3. 103
4. Exxon Corporation
5. Keystone Mills Well No. 34-L
6. Conroe South (Wilcox 9250)
7. Montgomery TX
8. 548.0 million cubic feet
9. June 22, 1979
10. Moran Utilities Company

1. 79-10754
2. 42-473-30298
3. 103
4. Exxon Corporation
5. Katy Gas Fld Consolidated Ut Well 43
6. Katy (IV)
7. Waller TX
8. 2555.0 million cubic feet
9. June 22, 1979
10. United Texas Transmission Co, Lone Star Gas Co

1. 79-10755
2. 42-473-30298
3. 103
4. Exxon Corporation
5. Katy Gas Fld. Consolidated UT Well 4
6. Katy (III-A)
7. Waller, TX
8. 2555.0 million cubic feet
9. June 22, 1979
10. United Texas Transmission Co., Lone Star Gas Co.

1. 79-10756
2. 42-235-31293
3. 103
4. Energy Reserves Group Inc.
5. Ela C. Sugg 61 No. 2
6. Ela Sugg (Wolfcamp)
7. Irion, TX
8. 180.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co.

1. 79-10757
2. 42-317-31934
3. 103
4. Hanley Company
5. University 7-31B Well No. 1 (24696)
6. Hutex (Dean)
7. Martin, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10758
2. 42-173-30451
3. 103
4. Hanley Company
5. C. J. Cox A. Well No. 4 (07149)
6. Calvin (Dean)
7. Glasscock, TX
8. 21.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Co.

1. 79-10759
2. 42-195-30624
3. 103
4. Mesa Petroleum Co.
5. ODC No. 2-38
6. Hansford (Lower Morrow)
7. Hansford, TX
8. 180.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline

1. 79-10760
2. 42-355-30833
3. 103
4. Pennzoil Producing Company
5. Gee No. 5 (U)
6. Agua Dulce
7. Nueces, TX
8. 18.0 million cubic feet
9. June 22, 1979
10. United Gas Pipeline Company

1. 79-10761
2. 42-355-31284
3. 102
4. Pennzoil Producing Company
5. Clura Driscoll No. A-14 (L)
6. Agua Dulce
7. Nueces, TX
8. 450.0 million cubic feet
9. June 22, 1979
10. United Gas Pipeline Company

1. 79-10762
2. 42-261-30429
3. 102 103
4. Exxon Corporation
5. Mrs. S. K. East 94-D 78619
6. Rita (10-L-II)
7. Kenedy, TX.

8. 456.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co. of Am

1. 79-10763
2. 42-165-00000
3. 103
4. Wood McShane & Thams
5. Mayo No. 1—RRC No. 75068
6. Block A-34 (Yates)
7. Gaines County, TX
8. 3.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10764
2. 42-047-30585
3. 102 103
4. Exxon Corporation
5. Santa Fe Ranch 35-F 79920
6. Santa Fe (D-38)
7. Brooks, TX
8. 350.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co. of Am.

1. 79-10765
2. 42-081-30687
3. 103
4. Enrich Oil Corporation
5. Bessie Walker No. 1
6. Bloodworth N. (Canyon 5650).
7. Coke, TX
8. 32.9 million cubic feet
9. June 22, 1979
10. Sun Gas Company

1. 79-10766
2. 42-427-31169
3. 103
4. Shell Oil Company
5. G E Neblett et al Gas Unit No. 3
6. La Copita (Vicksburg Z-2)
7. Starr, TX
8. 25.0 million cubic feet
9. June 22, 1979
10. Tennessee Gasline Pipeline Co

1. 79-10767
2. 42-427-30889
3. 103
4. Shell Oil Company
5. Bentsen Bros B No. 9
6. La Copita (Vicksburg Z).
7. Starr, TX
8. 270.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Co

1. 79-10768
2. 42-483-00000
3. 108
4. Pendleton and Vaughan
5. Atkins No. 1 TRRC ID No. 27000
6. East Panhandle
7. Wheeler, TX
8. 11.5 million cubic feet
9. June 22, 1979
10. Warren Petroleum Company

1. 79-10769
2. 42-371-31869
3. 107
4. GMW—O'Neill J I Jr
5. Raymal Eagle No 1 76352
6. Gomez No (Devonian)
7. Pecos, TX
8. 720.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10771
2. 42-235-31280
3. 103
4. Hytech Energy Corporation
5. Murphey B No 2
6. Spraberry (Trend Area)
7. Irion, TX
8. 29.4 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10772
2. 42-165-31274
3. 103
4. Hytech Energy Corporation
5. Hulse Unit No 1
6. Loop NE (Yates)
7. Gaines, TX
8. .4 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10773
2. 42-165-31275
3. 103
4. Hytech Energy Corporation
5. Smith Unit No 1
6. Loop NE (Yates)
7. Gaines, TX
8. 5.1 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10774
2. 42-165-31191
3. 103
4. Hytech Energy Corporation
5. King No 1
6. Loop NE (Yates)
7. Gaines, TX
8. 24.3 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10775
2. 42-235-31271
3. 103
4. Hytech Energy Corporation
5. Rocker B-85 No 1
6. Ela Sugg (Wolfcamp)
7. Irion, TX
8. 98.1 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10776
2. 42-235-31317
3. 103
4. Hytech Energy Corporation
5. Rocker B-85 No 2
6. Ela Sugg (Wolfcamp)
7. Irion, TX
8. 105.0 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10777
2. 42-235-31260
3. 103
4. Hytech Energy Corporation
5. Rocker B-86 No 1
6. Ela Sugg (Wolfcamp)
7. Irion, TX
8. 27.6 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10778
2. 42-235-31172
3. 103
4. Hytech Energy Corporation
5. Rocker B-87 No 1
6. Ela Sugg (Wolfcamp)
7. Irion, TX
8. 131.4 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10779
2. 42-235-31198
3. 103
4. Hytech Energy Corporation
5. Rocker B-87 No 2
6. Ela Sugg (Wolfcamp)
7. Irion, TX
8. 163.9 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10780
2. 42-235-31200
3. 103
4. Hytech Energy Corporation
5. Rocker B-88 No 1
6. Ela Sugg (Wolfcamp)
7. Irion, TX
8. 110.9 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10781
2. 42-317-31920
3. 103
4. Hytech Energy Corporation
5. Mabee C No 3
6. Spraberry (Trend Area)
7. Martin, TX
8. 2.6 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10782
2. 42-317-31628
3. 103
4. Hytech Energy Corporation
5. Mabee C No 2
6. Spraberry (Trend Area)
7. Martin, TX
8. 5.3 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10783
2. 42-311-30864
3. 103
4. Exxon Corporation
5. J C Dilworth No 13 ID #77114
6. Dilworth (Edwards Line)
7. McMullen, TX
8. 300.0 million cubic feet
9. June 22, 1979
10. Transcontinental Gas Pipeline Corp

1. 79-10784
2. 42-427-31243
3. 103
4. Exxon Corporation
5. Miguel Juarez Well No 6 78551
6. Kelsey South (Zone 24-A&B)
7. Starr, TX
8. 200.0 million cubic feet
9. June 22, 1979
10. Trunkline Gas Company

1. 79-10785
2. 42-247-30404
3. 102, 103
4. Exxon Corporation
5. Mrs A M K Bass Well #34 79684
6. Kelsey Deep (Zone 22-C) NW
7. Jim Hogg, TX
8. 146.0 million cubic feet

9. June 22, 1979
10. Trunkline Gas Company

1. 79-10786
2. 42-057-30848
3. 103
4. Exxon Corporation
5. Mrs E H Welder well No 46 5637
6. Heyser S (5400 #2)
7. Calhoun, TX
8. 55.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79-10787
2. 42-247-30400
3. 102 103
4. Exxon Corporation
5. Mrs A M K Bass well No 33 75313
6. Kelsey Deep (Zone 22-H NW)
7. Jim Hogg, TX
8. 200.0 million cubic feet
9. June 22, 1979
10. Trunkline Gas Company

1. 79-10788
2. 42-235-31174
3. 103
4. Hytech Energy Corporation
5. Murphey A No 2
6. Spraberry (Trend Area)
7. Irion, TX
8. 27.6 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10789
2. 42-235-31245
3. 103
4. Hytech Energy Corporation
5. Murphey B No 1
6. Spraberry (Trend Area)
7. Irion, TX
8. 30.6 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10790
2. 42-235-31251
3. 103
4. Hytech Energy Corporation
5. Rocker 8-88 No. 2
6. Ela Sugg (Wolfcamp)
7. Irion, TX
8. 43.0 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10791
2. 42-235-31156
3. 103
4. Hytech Energy Corporation
5. Rocker B-105 No. 2
6. Ela Sugg (Wolfcamp)
7. Irion, TX
8. 12.6 million cubic feet
9. June 22, 1979
10. Northern Natural

1. 79-10792
2. 42-211-31021
3. 103
4. Pioneer Production Corporation
5. L E Hoover Estate #1 (#79388)
6. Canadian East (Douglas)
7. Hemphill, TX
8. 300.0 million cubic feet
9. June 22, 1979
10. Pioneer Natural Gas Company

1. 79-10793
2. 42-211-31004
3. 103
4. Pioneer Production Corporation
5. Lindley #2 (79602)
6. Canadian East (Douglas)
7. Hemphill, TX
8. 190.0 million cubic feet
9. June 22, 1979
10. Pioneer Natural Gas Company

1. 79-10794
2. 42-247-30802
3. 102 103
4. Exxon Corporation
5. Mrs A M K Bass B well No. 15-D 77741
6. Kelsey Deep (Zone 20-A Seg 8)
7. Jim Hogg, TX
8. 300.0 million cubic feet
9. June 22, 1979
10. Trunkline Gas Company

1. 79-10795
2. 42-383-30843
3. 103
4. Hanley Company
5. University 58-19B well #1 (06963)
6. Spraberry (Trend Area)
7. Reagan, TX
8. 12.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10796
2. 42-497-31265
3. 103
4. Mitchell Energy Corporation
5. R D Grantham #3 79212
6. Bonnsville (Bend Congl Gas)
7. Wise, TX
8. 16.5 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co of America

1. 79-10797
2. 42-367-31029
3. 102
4. Mitchell Energy Corporation
5. J G Peipelman #1 77498
6. Lake Mineral Wells (4000 Conglomera)
7. Parker, TX
8. 330.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Company of America

1. 79-10798
2. 42-367-31166
3. 102
4. Mitchell Energy Corporation
5. Sarah Jane Howard #1 79704
6. Lake Mineral Wells (4000 Congl)
7. Parker, TX
8. 330.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co of America

1. 79-10799
2. 42-081-30636
3. 103
4. Exxon Corporation
5. I A B Unit well #513
6. I A B (Menielle Penn)
7. Coke, TX
8. 20.0 million cubic feet
9. June 22, 1979
10. Sun Gas Company

1. 79-10800
2. 42-135-32707
3. 103
4. Phillips Petroleum Company
5. Cowden—U No 3
6. Donnelly (San Andres)
7. Ector, TX
8. 28.5 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10801
2. 42-461-31238
3. 103
4. Phillips Petroleum Company
5. N Pembrook Spra U 6-4
6. Spraberry (Trend Area)
7. Upton, TX
8. 15.1 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10802
2. 42-461-31230
3. 103
4. Phillips Petroleum Company
5. N Pembrook Spra U 5-39
6. Spraberry (Trend Area)
7. Upton, TX
8. 5.4 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10803
2. 42-329-330774
3. 103
4. Phillips Petroleum Company
5. McAlister-B No 2
6. Spraberry (Trend Area)
7. Midland, TX
8. 9.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10804
2. 42-495-30508
3. 103
4. Phillips Petroleum Company
5. McCabe No 47
6. Halley
7. Winkler
8. 8.5 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10805
2. 42-135-32692
3. 103
4. Phillips Petroleum Company
5. Frank-B No 27
6. Goldsmith N (San Andres Con)
7. Ector, TX
8. 59.4 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company

1. 79-10806
2. 42-371-32482
3. 103
4. Phillips Petroleum Company
5. Mitchell-P No 1
6. Puckett East (Strawn)
7. Pecos, TX
8. 183.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10807
2. 42-371-32441
3. 103
4. Phillips Petroleum Company
5. Mitchell-N No 1
6. Puckett East (Strawn)
7. Pecos, TX
8. 183.0 million cubic feet

9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10808
2. 42-135-32161
3. 103
4. Phillips Petroleum Company
5. Embar No 52
6. Andector (Ellenburger)
7. Ector, TX
8. 13.1 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10809
2. 42-317-3200
3. 103
4. Hanley Company
5. University 7-31C well #1 (25068)
6. Hutex (Dean)
7. Martin, TX
8. 3.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10810
2. 42-317-31999
3. 103
4. Hanley Company
5. University 7-31D well #1 (25069)
6. Hutex (Dean)
7. Martin, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10811
2. 42-003-31710
3. 103
4. Hanley Company
5. University 7-38C well #1 (25106)
6. Hutex (Dean)
7. Andrews, TX
8. 3.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10812
2. 42-371-32621
3. 103
4. Mobil Oil Corporation
5. James O Neal No 5
6. Coyanosa N (Delaware)
7. Pecos, TX
8. 81.5 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company, Pioneer Natural Gas Co

1. 79-10813
2. 42-483-30514
3. 103
4. H L Brown Jr
5. T A Greenhouse No 1
6. Lott Ranch (Morrow UP)
7. Wheeler, TX
8. 96.0 million cubic feet
9. June 22, 1979
10. Michigan Wisconsin Pipe Line Cormpany

1. 79-10814
2. 42-483-30488
3. 103
4. H L Brown Jr
5. Thurman Horn No 1
6. Lott Ranch (Morrow Upper)
7. Wheeler, TX
8. 275.0 million cubic feet
9. June 22, 1979
10. Michigan Wisconsin Pipe Line Co

1. 79-10815
2. 42-483-30557
3. 103
4. H L Brown Jr
5. D E Atherton No 1
6. Lott Ranch (Morrow Up)
7. Wheeler, TX
8. 1825.0 million cubic feet
9. June 22, 1979
10. Michigan Wisconsin Pipe Line Company

1. 79-10816
2. 42-047-30339
3. 103
4. Exxon Corporation
5. Scott & Hopper 25-D 8908
6. Scott & Hopper (6750)
7. Brooks, TX
8. 50.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline

1. 79-10817
2. 42-261-30414
3. 102 103
4. Exxon Corporation
5. J G Kenedy Jr E #24 80041
6. El Paistle (G-25)
7. Kenedy, TX
8. 548.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co of America

1. 79-10818
2. 42-047-30585
3. 102 103
4. Exxon Corporation
5. Santa Fe Ranch #35-D 79936
6. Santa Fe (D-19)
7. Brooks, TX
8. 350.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co of America

1. 79-10819
2. 42-469-31363
3. 103
4. L & L Petroleum Corporation
5. C K McCan Jr #5
6. Salem
7. Victoria, TX
8. 90.0 million cubic feet
9. June 22, 1979
10. Texas Eastern Transmission Corp

1. 79-10820
2. 42-427-31196
3. 102 103
4. Exxon Corporation
5. Vicente Saenz State C No 6 77240
6. Strong (Saenz 7320)
7. Starr, TX
8. 60.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79-10821
2. 42-089-30669
3. 102
4. Cities Service Company
5. Schoeneberg A-1 73290
6. Dubina S (9150)
7. Colorado, TX
8. 58.0 million cubic feet
9. June 22, 1979
10. United Gas Pipe Line Co

1. 79-10822
2. 42-371-00000
3. 108
4. Saxet Oil Corporation
5. State A/C 101 Well No 2 19864
6. Fort Stockton
7. Pecos, TX
8. 13.7 million cubic feet
9. June 22, 1979
10. The Neuces Company

1. 79-10823
2. 42-427-31227
3. 103
4. Shell Oil Company
5. Bentsen Bros—State No 7
6. La Copita (Vicksburg Z)
7. Starr, TX
8. 70.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Co

1. 79-10824
2. 42-211-00000
3. 102
4. Amarex Inc
5. Fillingim—Teas Unit #1
6. Buffalo Wallow
7. Hemphill, TX
8. 1800.0 million cubic feet
9. June 22, 1979
10. Arkansas Louisiana Gas Company

1. 79-10825
2. 42-469-30586
3. 103
4. Sun Oil Company (Delaware)
5. McFaddin No 158
6. McFaddin (Tom Oconnor)
7. Victoria, TX
8. 12.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79-10826
2. 42-481-31260
3. 103
4. Sun Oil Company (Delaware)
5. J P Henderson Well #2
6. Wharco-Shilling (Slate)
7. Wharton, TX
8. 2.0 million cubic feet
9. June 22, 1979
10. Texas Eastern Transmission Corporation

1. 79-10827
2. 42-167-30351
3. 103
4. Sun Oil Company (Delaware)
5. Humphreys Well #8
6. Caplen (FB-8 1-Z)
7. Galveston, TX
8. 58.0 million cubic feet
9. June 22, 1979
10. Texas Gas Pipe Line Corporation

1. 79-10828
2. 42-089-30677
3. 103
4. Sun Oil Company (Delaware)
5. W R Frnka No 2
6. Wharco Schilling W
7. Colorado, TX
8. 395.0 million cubic feet
9. June 22, 1979
10. Texas Eastern Transmission Corporation

1. 79-10829
2. 42-071-30891
3. 103
4. Sun Oil Company (Delaware)
5. Simm Unit Well #4-C
6. Winnie N (5150)
7. Chambers, TX
8. 300.0 million cubic feet

9. June 22, 1979
10. Texas Eastern Transmission Corporation

1. 79-10830
2. 42-071-30891
3. 103
4. Sun Oil Company (Delaware)
5. Simm Unit Well #4-T
6. Winnie N (5350)
7. Chambers, TX
8. 330.0 million cubic feet
9. June 22, 1979
10. Texas Eastern Transmission Corporation

1. 79-10831
2. 42-183-30165
3. 103
4. Gulf Oil Corporation
5. Lawrence Unit Well #4 RRC #77062
6. Willow Springs (Cotton Valley)
7. Gregg, TX
8. 350.0 million cubic feet
9. June 22, 1979
10. United Gas Pipeline

1. 79-10832
2. 42-103-31956
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. M B McKnight #117
6. Running W North (Holt)
7. Crane, TX
8. 40.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10833
2. 42-103-31475
3. 103
4. Gulf Oil Corp
5. J T McElroy Cons No 936
6. McElroy
7. Crane, TX
8. .1 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10834
2. 42-103-31890
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. W A Estes #105
6. Sand Hills West
7. Crane, TX
8. 5.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10835
2. 42-461-31216
3. 103
4. Gulf Oil Corp
5. J T McElroy Cons No 1013
6. McElroy
7. Upton, TX
8. 3.5 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10836
2. 42-081-00000
3. 103
4. Texfel Petroleum Corp
5. 1 A—301 No 1
6. Arledge (Penn Sand)
7. Coke, TX
8. 146.0 million cubic feet
9. June 22, 1979
10. Sun Gas Company

1. 79-10837
2. 42-261-30239
3. 102 103
4. Exxon Corporation
5. J G Kenedy E 22-F 77509
6. El Paistle (J-62)
7. Kenedy, TX
8. 146.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co of America

1. 79-10838
2. 42-383-31256
3. 103
4. Hanley Company
5. University 10-10A Well #2 (07622)
6. Spraberry (Trend Area)
7. Reagan, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10839
2. 42-383-31270
3. 103
4. Hanley Company
5. University 10-11A Well #1 (07623)
6. Spraberry (Trend Area)
7. Reagan, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10840
2. 42-383-31269
3. 103
4. Hanley Company
5. University 10-11B Well #1 (07632)
6. Spraberry (Trend Area)
7. Reagan, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10841
2. 42-383-31268
3. 103
4. Hanley Company
5. University 10-11C Well #1 (07670)
6. Spraberry (Trend Area)
7. Reagan, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10842
2. 42-383-31267
3. 103
4. Hanley Company
5. University 10-11D Well #1 (07698)
6. Spraberry (Trend Area)
7. Reagan, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10843
2. 42-383-31291
3. 103
4. Hanley Company
5. University 58-18A Well #1 (07675)
6. Spraberry (Trend Area)
7. Reagan, TX
8. 5.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10844
2. 42-383-00000
3. 103
4. Hanley Company
5. T X L C Well #1 (07266)
6. Calvin (Dean)
7. Reagan, TX
8. 6.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10845
2. 42-383-00000
3. 103
4. Hanley Company
5. T X L D Well #1 (07267)
6. Calvin (Dean)
7. Reagan, TX
8. 5.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10846
2. 42-383-31252
3. 103
4. Hanley Company
5. University 10-10A Well No. 1 (07622)
6. Spraberry (Trend area)
7. Reagan, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10847
2. 42-081-30676
3. 103
4. Exxon Corporation
5. I A B Unit Well No. 110
6. I A B (Menielle Penn)
7. Coke, TX
8. 9.0 million cubic feet
9. June 22, 1979
10. Sun Gas Company

1. 79-10848
2. 42-003-31714
3. 103
4. Hanley Company
5. University 6-38 Well No. 1 (25144)
6. Hutex (Dean)
7. Andrews, TX
8. 6.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10849
2. 42-317-31939
3. 103
4. Hanley Company
5. University 7-25 Well No. 1 (24716)
6. Hutex (Dean)
7. Martin, TX
8. 7.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10850
2. 42-003-31584
3. 103
4. Hanley Company
5. University 7-25 Well No. 2 (24716)
6. Hutex (Dean)
7. Andrews, TX
8. 7.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10851
2. 42-003-31629
3. 103
4. Hanley Company
5. University 7-25A Well No. 1 (21927)
6. Hutex (Dean)
7. Andrews, TX
8. 4.0 million cubic feet
9. June 22, 1979

10. Phillips Petroleum Company
1. 79-10852
2. 42-003-31632
3. 103
4. Hanley Company
5. University 7-258 Well No. 1 (24937)
6. Hutex (Dean)
7. Andrews, TX
8. 4.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company
1. 79-10853
2. 42-317-31928
3. 103
4. Hanley Company
5. University 7-31A Well No. 1 (24664)
6. Hutex (Dean)
7. Martin, TX
8. 24.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company
1. 79-10854
2. 42-317-31947
3. 103
4. Henley Company
5. University 7-26 Well No. 1 (24760)
6. Hutex (Dean)
7. Martin, TX
8. 7.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company
1. 79-10855
2. 42-003-03911
3. 103
4. Sun Oil Company
5. University 7 No. 1
6. Fullerton
7. Andrews, TX
8. 21.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company, Amoco Production Co.
1. 79-10856
2. 42-003-03879
3. 103
4. Sun Oil Company (Deleware)
5. University 7 No. 2
6. Fullerton
7. Andrews, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company, Amoco Production Co
1. 79-10857
2. 42-365-30839
3. 103
4. Crystal Oil and Land Company
5. Jernigan #1
6. Panolo
7. Panola, TX
8. 165.0 million cubic feet
9. June 22, 1979
10. United Gas Pipeline Company
1. 79-10858
2. 42-219-32311
3. 103
4. Gulf Oil Corporation
5. M G Gurdon No. 28
6. Slaughter (ABO)
7. Hockley, TX
8. 32.9 million cubic feet
9. June 22, 1979
10. Amoco Production Company
1. 79-10859
2. 42-475-31613
3. 103
4. Gulf Oil Corp
5. Crawar Filed Unit #6
6. Crawar (Glorieta)
7. Ward TX
8. 10.0 million cubic feet
9. June 22, 1979
10 Transwestern Pipeline Co
1. 79-10860
2. 42-103-31851
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. State EI #8
6. Dune
7. Crane, TX
8. 28.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co
1. 79-10861
2. 42-003-31162
3. 103
4. Gulf Oil Corporation
5. F E Gardner Et Al No. 3
6. Means
7. Andrews TX
8. .9 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company
1. 79-10862
2. 42-003-31160
3. 103
4. Gulf Oil Corporation
5. F E Gardner Et Al No. 2
6. Means
7. Andrews TX
8. .6 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company
1. 79-10863
2. 42-103-31880
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. M B Mcknight #15
6. Running W North (Holt)
7. Crane TX
8. 19.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co
1. 79-10864
2. 42-103-31902
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. W N Waddell Et Al #1103
6. C-Bar (San AndresS)
7. Crane TX
8. 4.0million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co
1. 79-10865
2. 42-003-31161
3. 103
4. Gulf Oil Corporation
5. F E Gardner Et Al No. 4
6. Means
7. Andrews TX
8. 1.5 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company
1. 79-10866
2. 42-103-31879
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. M F Henderson #165
6. C-Bar (San Andres)
7. Crane TX
8. 3.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co
1. 79-10867
2. 42-103-31840
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. State EC #4
6. Duane
7. Crane TX
8. 32.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co
1. 79-10868
2. 42-219-32350
3. 103
4. Gulf Oil Corporation
5. M G Cordon No. 31
6. Slaughter (ABO)
7. Hockley TX
8. 9.9 million cubic feet
9. June 22, 1979
10. Amoco Production Company
1. 79-10869
2. 42-249-30558
3. 103
4. Sun Oil Company (Delaware)
5. Seeligson Unit Well No. 0142BL
6. Seeligson (Zone 12-B-05)
7. Jim Wells TX
8. 700.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company
1. 79-10870
2. 42-249-30558
3. 103
4. Sun Oil Company (Delaware)
5. Seelingson Unit Well No. 0142BU
6. Seeligson (Zone 09-A)
7. Jim Wells TX
8. 700.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company
1. 79-10871
2. 42-249-30854
3. 103
4. Sun Oil Company (Delaware)
5. Seeligson Unit No. 0143BL
6. Seeligson (Zone 20-B-03)
7. Jim Wells TX
8. 134.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company
1. 79-10872
2. 42-249-30854
3. 103
4. Sun Oil Company (Deleware)
5. Seeligson Unit No. 014BU
6. Seeligson (Zone 18-A-05)
7. Jim Wells TX
8. 134.0 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company
1. 79-10873
2. 42-365-30848
3. 103
4. Crystal Oil and Land Company
5. Jernigan #4
6. Panola
7. Panola TX
8. 165.0 million cubic feet

9. June 22, 1979
10. United Gas Pipeline Company

1. 79-10874
2. 42-365-30847
3. 103
4. Crystal Oil and Land Company
5. Jernigan #3
6. Panola
7. Panola TX
8. 165.0 million cubic feet
9. June 22, 1979
10. United Gas Pipeline Company

1. 79-10875
2. 42-365-30840
3. 103
4. Crystal Oil and Land Company
5. Jernigan #2
6. Panola
7. Panola TX
8. 165.0 million cubic feet
9. June 22, 1979
10. United Gas Pipeline Company

1. 79-10876
2. 42-365-30853
3. 103
4. Crystal Oil and Land Company
5. Jernigan #9
6. Panola
7. Panola, TX
8. 165.0 million cubic feet
9. June 22, 1979
10. United Gas Pipeline Company

1. 79-10877
2. 42-365-30836
3. 103
4. Crystal Oil and Land Company
5. Reavis #1
6. Panola
7. Panola, TX
8. 15.0 million cubic feet
9. June 22, 1979
10. United Gas Pipeline Company

1. 79-10878
2. 42-365-30832
3. 103
4. Crystal Oil and Land Company
5. Cline #9
6. Panola
7. Panola, TX
8. 22.0 million cubic feet
9. June 22, 1979
10. United Gas Pipeline Company

1. 79-10879
2. 42-339-30403
3. 102
4. Mitchell Energy Corporation
5. Pinehurst Gas Unit #5 ID #79595
6. Pinehurst (Wilcox G)
7. Montgomery County, TX
8. 26.9 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79-10880
2. 42-047-30622
3. 102 103
4. Exxon Corporation
5. Santa Fe Ranch #39-F 09224
6. Santa Fe (E-03)
7. Brooks, TX
8. 20.0 million cubic feet
9. June 22, 1979
10. Natl Gas Pipeline Co of AM

1. 79-10881
2. 42-401-30585
3. 103
4. Pioneer Production Corporation
5. A M Wilkins Gas Unit #1 80294
6. Dirgin (Cotton Valley)
7. Rusk, TX
8. 17.0 million cubic feet
9. June 22, 1979
10. Delhi Gas Pipeline Corporation

1. 79-10882
2. 42-401-30586
3. 103
4. Pioneer Production Corporation
5. Adron Isaac Gas Unit 78592
6. Dirgin (Cotton Valley)
7. Rusk, TX
8. 57.0 million cubic feet
9. June 22, 1979
10. Delhi Gas Pipeline Corporation

1. 79-10883
2. 42-475-30982
3. 103
4. Gulf Oil Corporation
5. J C Gunn Et Al A Well No 3
6. Rhoda Walker (Canyon 5900)
7. Ward, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. Delhi Gas Pipeline Corporation

1. 79-10884
2. 42-389-30956
3. 103
4. Gulf Oil Corporation
5. G C Westervelt Well No 2
6. Worsham (Delaware Sand)
7. Reeves, TX
8. 3.0 million cubic feet
9. June 22, 1979
10. Transwestern Pipeline Company

1. 79-10885
2. 42-475-31690
3. 103
4. Gulf Oil Corporation
5. J C Gunn Et Al A Well No 4
6. Rhoda Walker (Canyon 5900)
7. Ward, TX
8. 350.0 million cubic feet
9. June 22, 1979
10. Delhi Gas Pipeline Corp

1. 79-10886
2. 42-103-31919
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. M B McKnight #116
6. Running W North (Holt)
7. Crane, TX
8. 17.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10887
2. 42-103-31767
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. J B Tubb A #32
6. Sand Hills (McKnight)
7. Crane, TX
8. 17.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10888
2. 42-211-31045
3. 103
4. Diamond Shamrock Corporation
5. Billy Jarvis & Sons Inc F No 1
6. Canadian SE
7. Hemphill, TX
8. 300.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company, Pioneer Natural Gas Co

1. 79-10889
2. 42-295-30586
3. 103
4. Diamond Shamrock Corporation
5. Valentine Schoenhals Et Al A No 1
6. Lipscomb
7. Lipscomb, TX
8. 100.0 million cubic feet
9. June 22, 1979
10.

1. 79-10890
2. 42-295-30601
3. 103
4. Diamond Shamrock Corporation
5. Arthur Becker Jr Et Al No 2
6. Bradford
7. Lipscomb, TX
8. 100.0 million cubic feet
9. June 22, 1979
10.

1. 79-108891
2. 42-065-00000
3. 108
4. Dorchester Gas Producing Co
5. McConnell No 3 (24366)
6. West Panhandle
7. Carson, TX
8. 6.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co

1. 79-10892
2. 42-469-00000
3. 108
4. Monsanto Company
5. Leona Reeves No 1
6. Cologne (1250)
7. Victoria, TX
8. 16.7 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79-10893
2. 42-499-00000
3. 102
4. Fair Oil LTD
5. J F Johnson Estate Unit #1
6. B-J (Cloyd) Field
7. Wood, TX
8. 547.5 million cubic feet
9. June 22, 1979
10. Arkansas-Louisiana Gas Company

1. 79-10894
2. 42-469-00000
3. 108
4. Monsanto Company
5. Leona Reeves No 2-C
6. Cologne (1000)
7. Victoria, TX
8. 2.9 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79-10895
2. 42-469-00000
3. 108
4. Monsanto Company
5. Leona Reeves No 2-T
6. Cologne (1250)
7. Victoria, TX
8. 1.8 million cubic feet

9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79-10896
2. 42-435-00000
3. 108
4. Lively Exploration Company
5. Aldwell 22 #3 61867
6. Aldwell Ranch (Canyon) Field
7. Sutton, TX
8. 10.1 million cubic feet
9. June 22, 1979
10. Lovaca Gathering Company

1. 79-10897
2. 42-435-00000
3. 108
4. Lovely Exploration Company
5. Aldwell 8 #1A 54724
6. Aldwell Ranch (Canyon) Field
7. Sutton, TX
8. 2.8 million cubic feet
9. June 22, 1979
10. Lovaca Gathering Company

1. 79-10898
2. 42-383-00000
3. 103
4. Michel T Halbouty
5. Rucker B LSE #8 07457
6. Sprayberry (Trend area)
7. Reagan TX
8. 13.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10899
2. 42-383-31220
3. 103
4. Marathon Oil Company
5. University BL Well No 4
6. Big Lake (Fusselman)
7. Reagan, TX
8. 15.0 million cubic feet
9. June 22, 1979
10. Dorchester Gas Producing Company

1. 79-10900
2. 42-103-31906
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. W A Estes #106
6. Sand Hills (West)
7. Crane, TX
8. 13.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10901
2. 42-211-30871
3. 103
4. Donald C Slawson
5. Mahler Unit #2 RRC #74825
6. Parsell South Morrow Upper Se
7. Roberts, TX
8. 350.0 million cubic feet
9. June 22, 1979
10. El Paso natural Gas Co

1. 79-10902
2. 42-211-30915
3. 102
4. Hoover & Bracken Energies
5. Alexander #1-3
6. Washita Creek (Morrow Upper)
7. Hemphill, TX
8. 3650.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co

1. 79-10903
2. 42-311-30867
3. 102
4. Shell Oil Company
5. McClaugherty No 1
6. Tilden E (Edwards)
7. McMullen, TX
8. 540.0 million cubic feet
9. June 22, 1979
10. Transcontinental Gas Pipeline Corp

1. 79-10904
2. 42-427-31192
3. 102
4. Shell Oil Company
5. Garza-State No 15
6. Rincon North Vicksburg 8230
7. Starr, TX
8. 100.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co of America

1. 79-10905
2. 42-105-00000
3. 108
4. Rodman Petroleum Corporation
5. Harvick 47 #1
6. Ozona (Canyon Sand)
7. Crockett, TX
8. 2.9 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10906
2. 42-105-00000
3. 108
4. Rodman Petroeleum Corporation
5. V I Pierce #1
6. Ozona (Canyon Sand)
7. Crockett, TX
8. .5 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company

1. 79-10907
2. 42-457-00000
3. 102
4. Texas City Refining Inc
5. Exxon Section 1 Fee No 1
6. Warren (7480)
7. Tyler, TX
8. 146.0 million cubic feet
9. June 22, 1979
10. Tennessee Pipeline Company

1. 79-10908
2. 42-469-00000
3. 108
4. Monsanto Company
5. Mettie Johnston No 2
6. Cologne (1000)
7. Victoria, TX
8. 2.7 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79-10909
2. 42-469-00000
3. 108
4. Monsanto Company
5. H L Horadam No 1-T
6. Cologne (1600)
7. Victoria, TX
8. .5 million cubic feet
9. June 22, 1979
10. Tennessee Gas Pipeline Company

1. 79-10910
2. 42-495-30518
3. 103
4. Gulf Oil Corporation
5. Keystone Cattle Co Well No 332
6. Keystone (Colby)
7. Winkler, TX
8. 44.0 million cubic feet
9. June 22, 1979
10. Cabot Corporation

1. 79-10911
2. 42-389-30998
3. 103
4. Gulf Oil Corporation
5. L Horry et al Well No 9
6. Worsham (Cherry Canyon)
7. Reeves, TX
8. 50.0 million cubic feet
9. June 22, 1979
10. Transwestern Pipeline Company

1. 79-10912
2. 42-103-00000
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. J B Tubb et al #27
6. Sand Hills (Tubb)
7. Crane, TX
8. 38.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10913
2. 42-103-00000
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. W A Estes #100
6. Sand Hills West
7. Crane, TX
8. 7.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10914
2. 42-329-00000
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. M B McKnight #114
6. Sand Hills (Wolfcamp)
7. Crane, TX
8. 10.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co

1. 79-10915
2. 42-371-32510
3. 103
4. Gulf Oil Corp
5. L H Millar et al No 16
6. Putnam (Wolfcamp)
7. Pecos, TX
8. 270.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10916
2. 42-227-31143
3. 103
4. Gulf Oil Corporation
5. Murray CS No 10
6. Iatan (San Andres)
7. Howard, TX
8. .1 million cubic feet
9. June 22, 1979
10. Getty Oil Company

1. 79-10917
2. 42-003-31659
3. 103
4. Gulf Oil Corporation
5. State PW No 1
6. Lacaff (Dean)
7. Andrews, TX
8. 3.2 million cubic feet
9. June 22, 1979

10. Phillips Petroleum Company
1. 79-10918
2. 42-495-30517
3. 103
4. Gulf Oil Corporation
5. Keystone Cattle Co Well No 333
6. Keystone (Colby)
7. Winkler, TX
8. 142.0 million cubic feet
9. June 22, 1979
10. Cabot Corporation
1. 79-10919
2. 42-103-00000
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. W N Waddell et al Tr I #1095
6. McKee (Wolfcamp)
7. Crane, TX
8. 72.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co
1. 79-10920
2. 42-103-00000
3. 103
4. Warren Pet Co Div/Gulf Oil Corp
5. J B Tubb A #33
6. Sand Hills (Tubb)
7. Crane, TX
8. 114.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co
1. 79-10921
2. 42-179-00000
3. 108
4. Dorchester Gas Producing Co
5. Sheridan No 1 (23249)
6. West Panhandle
7. Gray, TX
8. 6.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co
1. 79-10922
2. 42-065-00000
3. 108
4. Dorchester Gas Producing Co
5. Bednorz No 2 (24324)
6. West Panhandle
7. Carson, TX
8. 5.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Co
1. 79-10923
2. 42-547-30293
3. 103
4. Cities Service Company
5. Sturrock A-1
6. Sugar Creek (Woodbine)
7 Tyler, TX
8. 365.0 million cubic feet
9. June 22, 1979
10. United Gas Pipe Line Co
1. 79-10924
2. 42-461-00000
3. 103
4. Warren Pet Co A Div of Gulf Oil
5. J T McElroy No 939-D
6. McElroy Southeast (Devonian)
7. Uption, TX
8. 54.9 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Company
1. 79-10925
2. 42-355-00000
3. 102
4. Maynard Oil Company
5. Gabriel #2
6. Clarkwood S (McKamey)
7. Nueces, TX
8. 1080.0 million cubic feet
9. June 22, 1979
10.
1. 79-10926
2. 42-445-00000
3. 102
4. NRM Petroleum Corporation
5. Hoffman #1-A
6. Becker (Yates) Field
7. Terry, TX
8. 730.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas
1. 79-10927
2. 42-413-30681
3. 103
4. M Brad Bennett Inc & RKH Ltd
5. Bruton #1
6. Klatt (Canyon)
7. Schleicher, TX
8. 36.5 million cubic feet
9. June 22, 1979
10. Northern Natural Gas Company
1. 79-10928
2. 42-445-00000
3. 102
4. NRM Petroleum Corporation
5. Goodpasture No 1
6. Becker (Yates) Field
7. Terry, TX
8. 730.0 million cubic feet
9. June 22, 1979
10. Northern Natural Gas
1. 79-10929
2. 42-215-30768
3. 103
4. Shell Oil Company
5. Dixie Mortgage-Hopkins GU No 2
6. Mc Cook E (Vicksburg-Lo)
7. Hidalgo, TX
8. 270.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Co of America
1. 79-10930
2. 42-215-30858
3. 103
4. Shell Oil Company
5. A A Mc Allen No 60
6. Mc Allen (Vicksburg SN)
7. Hidalgo, TX
8. 310.0 million cubic feet
9. June 22, 1979
10. S Texas Natural Gas Gathering Co
1. 79-10931
2. 42-215-30856
3. 103
4. Shell Oil Company
5. A A McAllen No 54
6. McAllen Ranch (Vicksburg R-1)
7. Hidalgo, TX
8. 400.0 million cubic feet
9. June 22, 1979
10. So Texas Natural Gas Gathering Co
1. 79-10932
2. 42-215-30788
3. 103
4. Shell Oil Company
5. A A McAllen No 53
6. McAllen Ranch (Vicksburg R)
7. Hidalgo, TX
8. 140.0 million cubic feet
9. June 22, 1979
10. So Texas Natural Gas Gathering Co
1. 79-10933
2. 42-427-31248
3. 103
4. Shell Oil Company
5. Thomas-Rife Gas Unit No 8
6. Rincon North (Vicksburg 8200 SE)
7. Starr, TX
8. 220.0 million cubic feet
9. June 22, 1979
10. Natural Gas Pipeline Company of Am
1. 79-10934
2. 42-495-30948
3. 103
4. Gulf Oil Corporation
5. Keystone Cattle Co Well No 339
6. Keystone (Colby)
7. Winkler, TX
8. 26.0 million cubic feet
9. June 22, 1979
10. Cabot Corporation
1. 79-10935
2. 42-495-30949
3. 103
4. Gulf Oil Corporation
5. Keystone Cattle Co Well No 338
6. Keystone (Colby)
7. Winkler, TX
8. 18.0 million cubic feet
9. June 22, 1979
10. Cabot Corporation
1. 79-10936
2. 42-495-30966
3. 103
4. Gulf Oil Corporation
5. Keystone Cattle Co Well No 337
6. Keystone (Colby)
7. Winkler TX
8. 34.0 million cubic feet
9. June 22, 1979
10. Cabot Corporation
1. 79-10937
2. 42-495-30519
3. 103
4. Gulf Oil Corporation
5. Keystone Cattle Co Well No 335
6. Keystone (Colby)
7. Winkler TX
8. 29.0 million cubic feet
9. June 22, 1979
10. Cabot Corporation
1. 79-10938
2. 42-103-00000
3. 103
4. Warren Pet Co Div/Gulf Oil Corporation
5. J B Tubb A #33
6. Sand Hills (McKnight)
7. Crane TX
8. 208.0 million cubic feet
9. June 22, 1979
10. El Paso Natural Gas Co
1. 79-10939
2. 42-495-30885
3. 103
4. Gulf Oil Corporation
5. Keystone Cattle Co Well No 336
6. Keystone (Colby)
7. Winkler TX
8. 200.0 million cubic feet
9. June 22, 1979
10. Cabot Corporation

1. 79-10940
2. 42-495-30524
3. 103
4. Gulf Oil Corporation
5. Keystone Cattle Co Well No 334
6. Keystone (Colby)
7. Winkler TX
8. 34.0 million cubic feet
9. June 22, 1979
10. Cabot Corporation

1. 79-10941
2. 42-135-33019
3. 103
4. American Petrofina Company of Texas
5. E Penwell S A Unit No 309
6. Penwell (San Andres)
7. Ector TX
8. 3.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company.

1. 79-10942
2. 42-135-33201
3. 103
4. American Petrofina Company of Texas
5. E Penwell S A Unit No 1810
6. Penwell (San Andres)
7. Ector TX
8. 1.5 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10943
2. 42-135-33020
3. 103
4. American Petrofina Company of Texas
5. E Penwell S A Unit No 809
6. Penwell (San Andres)
7. Ector TX
8. 3.0 million cubic feet
9. June 22, 1979
10. Phillips Petroleum Company

1. 79-10744
2. 42-339-30406
3. 103
4. Exxon Corporation
5. Conroe Field Unit Well No 109
6. Conroe Field
7. Montgomery TX
8. 130.0 million cubic feet
9. June 22, 1979
10. Moran Utilities Company

1. 79-10770
2. 42-365
3. 108
4. Alfred C Glassell Jr
5. Dunaway Unit #4
6. Carthage
7. Panola, TX
8. 12.6 million cubic feet
9. June 22, 1979
10. Arkansas-Louisiana Gas Co

West Virginia Department of Mines, Oil and Gas Division

1. Control Number (FERC/State)
2. API Well Number
3. Section of NGPA
4. Operator
5. Well Name
6. Field or OCS Area Name
7. County, State or Block No.
8. Estimated Annual Volume
9. Date Received at FERC
10. Purchaser(s)

1. 79-10534
2. 47-019-00160
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #44-041110
6. Paint Creek
7. Fayette WV
8. 3.8 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10535
2. 47-019-00162
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #50-042630
6. Paint Creek
7. Fayette WV
8. 15.8 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10536
2. 47-019-00167
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #54-046820
6. Paint Creek
7. Fayette WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10537
2. 47-039-01664
3. 108
4. Ashland Exploration Inc
5. Briar Mtn Coal & Coke #1-026110
6. Paint Creek
7. Kanawha WV
8. 5.4 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10538
2. 47-039-02057
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #46-042180
6. Paint Creek
7. Kanawha WV
8. 11.0 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10539
2. 47-039-01985
3. 108
4. Ashland Exploration Inc.
5. J F B Peyton #1-036800
6. Paint Creek
7. Kanawha WV
8. 2.5 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10540
2. 47-039-02045
3. 108
4. Ashland Exploration Inc
5. Kanawha Valley Bank #2-041080
6. Paint Creek
7. Kanawha WV
8. 9.3 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10541
2. 47-109-00424
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #138-023530
6. Logan Wyoming
7. Wyoming WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10542
2. 47-109-00421
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #135-023100
6. Logan Wyoming
7. Wyoming WV
8. 11.9 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10543
2. 47-109-00426
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #139-023570
6. Logan Wyoming
7. Wyoming WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10544
2. 47-039-01848
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #24-034210
6. Paint Creek
7. Kanawha WV
8. 4.0 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10545
2. 47-039-01911
3. 108
4. Ashland Exploration Inc
5. Bedford Land Co #7-035050
6. Paint Creek
7. Kanawha WV
8. 6.3 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10546
2. 47-039-01892
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #28-035750
6. Paint Creek
7. Kanawha WV
8. 21.4 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10547
2. 47-109-00354
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #102-017410
6. Logan Wyoming
7. Wyoming WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10548
2. 47-109-00345
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #99-016990
6. Logan Wyoming
7. Wyoming WV
8. 10.1 million cubic feet
9. June 25, 1979

10. Consolidated Gas Supply Corp
1. 79-10549
2. 47-109-00349
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #100-017030
6. Logan Wyoming
7. Wyoming WV
8. 11.9 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10550
2. 47-109-00350
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #101-017040
6. Logan Wyoming
7. Wyoming WV
8. 11.9 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10551
2. 47-109-00355
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #104-017560
6. Logan Wyoming
7. Wyoming WV
8. 7.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10552
2. 47-109-00403
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #128-021700
6. Logan Wyoming
7. Wyoming WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10553
2. 47-109-00391
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #125-020730
6. Logan Wyoming
7. Wyoming, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10554
2. 47-109-00382
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #122-020170
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10555
2. 47-109-00393
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #126-021040
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10556
2. 47-109-00398
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #127-021550
6. Logan Wyoming
7. Wyoming, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10557
2. 47-109-00423
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #137-023420
6. Logan Wyoming
7. Wyoming, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10558
2. 47-109-00380
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #121-019900
6. Logan Wyoming
7. Wyoming, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10559
2. 47-109-00319
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #83-016300
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10560
2. 47-109-00318
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #22-016290
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10561
2. 47-109-00321
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #85-016350
6. Logan Wyoming
7. Wyoming, WV
8. 11.9 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10562
2. 47-109-00324
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #86-016370
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10563
2. 47-109-00326
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #87-016380
6. Logan Wyoming
7. Wyoming, WV
8. 7.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10564
2. 47-039-01686
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #4-027790
6. Paint Creek
7. Kanawha, WV
8. 11.4 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc
1. 79-10565
2. 47-039-01693
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #5-029490
6. Paint Creek
7. Kanawha, WV
8. 13.0 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc
1. 79-10566
2. 47-039-01925
3. 108
4. Ashland Exploration Inc
5. Bedford Land Co #8-035130
6. Paint Creek
7. Kanawha, WV
8. 13.8 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc
1. 79-10567
2. 47-045-00214
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #76-015670
6. Logan Wyoming
7. Logan, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10568
2. 47-109-00413
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #132-022180
6. Logan Wyoming
7. Wyoming, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10569
2. 47-109-00410
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #131-022090
6. Logan Wyoming
7. Wyoming, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10570
2. 47-109-00408
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #130-021970
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10571
2. 47-045-00215
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #77-015690
6. Logan Wyoming
7. Logan, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10572
2. 47-109-00310
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #81-016160
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10573
2. 47-045-00462
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #142-023650
6. Logan Wyoming
7. Logan, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10574
2. 47-109-00286
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #71-015460
6. Logan Wyoming
7. Wyoming, WV
8. 11.9 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10575
2. 47-109-00287
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #72-015470
6. Logan Wyoming
7. Wyoming, WV
8. 11.9 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10576
2. 47-109-00288
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #73-015480
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10577
2. 47-019-00151
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #42-040420
6. Paint Creek
7. Fayette, WV
8. 3.6 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10578
2. 47-019-00152
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #43-040500
6. Paint Creek
7. Fayette, WV
8. 13.5 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10579
2. 47-109-00414
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #133-022190
6. Logan Wyoming
7. Wyoming, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10580
2. 47-109-00418
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #134-022300
6. Logan Wyoming
7. Wyoming, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10581
2. 47-039-01675
3. 108
4. Ashland Exploration Inc
5. Briar Mtn Coal & Coke #2-026630
6. Paint Creek
7. Kanawha, WV
8. 5.6 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10582
2. 47-039-01850
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #25-034250
6. Paint Creek
7. Kanawha, WV
8. 8.9 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10583
2. 47-039-01868
3. 108
4. Ashland Exploration Inc
5. Bedford Land Co #4—034390
6. Paint Creek
7. Kanawha, WV
8. 6.9 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10584
2. 47-039-01878
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #27—034430
6. Paint Creek
7. Kanawha, WV
8. 14.1 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10585
2. 47-019-00134
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #30—037570
6. Paint Creek
7. Fayette, WV
8. 4.5 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10586
2. 47-019-00139
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #34—038670
6. Paint Creek
7. Fayette, WV
8. 15.3 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10587
2. 47-019-00140
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #35—038810
6. Paint Creek
7. Fayette, WV
8. 6.4 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10588
2. 47-019-00142
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #37—039070
6. Paint Creek
7. Fayette, WV
8. 3.7 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10589
2. 47-019-00145
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #39—039740
6. Paint Creek
7. Fayette, WV
8. 10.4 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10590
2. 47-019-00150
3. 108
4. Ashland Exploration Inc
5. Eastern Gas & Fuel #41—040320
6. Paint Creek
7. Fayette, WV
8. 9.7 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Inc

1. 79-10591
2. 47-109-00330
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #88—016440
6. Logan Wyoming
7. Wyoming, WV
8. 9.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10592
2. 47-109-00334
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #90—016530
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10593

2. 47-109-00335
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #91—016540
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10594
2. 47-109-00336
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #93—16580
6. Logan Wyoming
7. Wyoming, WV
8. 7.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10595
2. 47-109-00339
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #94—016660
6. Logan Wyoming
7. Wyoming, WV
8. 11.9 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10596
2. 47-109-00340
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #95-016760
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10597
2. 47-109-00343
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #96—016780
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10598
2. 47-045-00256
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #103—017530
6. Logan Wyoming
7. Logan, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10599
2. 47-045-00238
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #98—016960
6. Logan Wyoming
7. Logan, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10600
2. 47-045-00227
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #97—016790
6. Logan Wyoming
7. Logan, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10601
2. 47-045-00224
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #92—016550
6. Logan Wyoming
7. Logan, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10602
2. 47-045-00222
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #89—016450
6. Logan Wyoming
7. Logan, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10603
2. 47-045-00107
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #1—011690
6. Logan Wyoming
7. Logan, WV
8. 17.0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10604
2. 47-045-00261
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #107—018150
6. Logan Wyoming
7. Logan, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10605
2. 47-109-00171
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #7—014330
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10606
2. 47-109-00154
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #5—014170
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10607
2. 47-109-00138
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #4—013870
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10608
2. 47-109-00108
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #3—012760
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10609
2. 47-005-00655
3. 108
4. Ashland Exploration Inc
5. Siler Coal Land Co Fee #21—011830
6. Siler
7. Boone, WV
8. 5.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10610
2. 47-005-00644
3. 108
4. Ashland Exploration Inc
5. Siler Coal Land Co Fee #20—011820
6. Siler
7. Boone, WV
8. 5.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10611
2. 47-005-00624
3. 108
4. Ashland Exploration Inc
5. Siler Coal Land Co Fee #19—011640
6. Siler
7. Boone, WV
8. 5.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10612
2. 47-005-00623
3. 108
4. Ashland Exploration Inc
5. Siler Coal Land Co Fee #18—011630
6. Siler
7. Boone, WV
8. 5.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Transmission Inc

1. 79-10613
2. 47-005-00622
3. 108
4. Ashland Exploration Inc
5. Siler Coal Land Co Fee #17-011620
6. Siler
7. Boone, WV
8. 5.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10614
2. 47-039-03192
3. 108
4. Ashland Exploration Inc
5. J A Osborne #14-001460
6. Old Field
7. Kanawha, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10615
2. 47-039-0319

3. 108
4. Ashland Exploration Inc
5. J A Osborne #12–001440
6. Old Field
7. Kanawha, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10616
2. 47–039–03189
3. 108
4. Ashland Exploration Inc
5. J A Osborne #8–001400
6. Old Field
7. Kanawha, WV
8. 6.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10617
2. 47–039–03188
3. 108
4. Ashland Exploration Inc
5. J A osborne #7–001390
6. Old Field
7. Kanawha, WV
8. 6.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10618
2. 47–039–03187
3. 108
4. Ashland Exploration Inc
5. J A Osborne #6–001380
6. Old Field
7. Kanawha, WV
8. 6.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10619
2. 47–039–03186
3. 108
4. Ashland Exploration Inc
5. J A Osborne #3–001350
6. Old Field
7. Kanawha, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10620
2. 47–109–00246
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #62–014930
6. Logan Wyoming
7. Wyoming, WV
8. 7.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10621
2. 47–109–00241
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #60–014850
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10622
2. 47–109–00237
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #59–014840
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10623
2. 47–109–00236
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #58–014830
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10624
2. 47–109–00233
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #57–014790
6. Logan Wyoming
7. Wyoming, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10625
2. 47–109–00232
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #56–014780
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10626
2. 47–033–01914
3. 103
4. Allegheny Land & Mineral Co
5. A–748
6. Union District
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10627
2. 47–033–01248
3. 103
4. Allegheny Land & Mineral Co
5. A–747
6. Union District
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10628
2. 47–001–01066
3. 103
4. Allegheny land & Mineral Co
5. A–755
6. Cove District
7. Barbour, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10629
2. 47–091–00177
3. 103
4. Allegheny land & Mineral Co
5. A–756
6. Knottsville District
7. Taylor, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10630
2. 47–033–01170
3. 103
4. Allegheny Land & Mineral Co
5. A–726
6. Union District
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10631
2. 47–033–01147
3. 103
4. Allegheny Land & Mineral Co
5. A–671
6. Union District
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10632
2. 47–041–02548
3. 103
4. Allegheny Land & Mineral Co
5. A–793
6. Hackers Creek District
7. Lewis, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10633
2. 47–033–01945
3. 103
4. Allegheny Land & Mineral Co
5. A–774
6. Union District
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10634
2. 47–103–00624
3. 103
4. Allegheny Land & Mineral Co
5. A–668
6. Centerpoint District
7. Wetzel, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10635
2. 47–017–01880
3. 103
4. Allegheny Land & Mineral Co
5. A–730
6. Southwest District
7. Doddridge, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10636
2. 47–097–01772
3. 103
4. Allegheny Land & Mineral Co
5. A–654
6. Washington Dist
7. Upshur, WV
8. 37.3 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79–10637
2. 47–033–01258
3. 103
4. Allegheny Land & Mineral Co

5. A-685
6. Union District
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10638
2. 47-017-02316
3. 103
4. Allegheny Land & Mineral Co
5. A-687
6. Greenbrier District
7. Doddridge, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10639
2. 47-033-01072
3. 103
4. Allegheny Land & Mineral Co
5. A-688
6. Eagle District
7. Harrison, WV
8. 60.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10640
2. 47-017-02308
3. 103
4. Allegheny Land & Mineral Co
5. A-689
6. Southwest District
7. Doddridge, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10641
2. 47-017-02309
3. 103
4. Allegheny Land & Mineral Co
5. A-690
6. Southwest District
7. Doddridge, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10642
2. 47-033-01183
3. 103
4. Allegheny Land & Mineral Co
5. A-722
6. Sardis Dist
7. Harrison, WV
8. 47.0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10643
2. 47-033-01169
3. 103
4. Allegheny Land & Mineral Co
5. A-714
6. Eagle Dist
7. Harrison, WV
8. 38.7 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10644
2. 47-033-01148
3. 103
4. Allegheny Land & Mineral Co
5. A-713
6. Sardis District
7. Harrison, WV
8. 41.6 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10645
2. 47-033-01218
3. 103
4. Allegheny Land & Mineral Co
5. A-712
6. Sardis District
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10646
2. 47-001-00991
3. 103
4. Allegheny Land & Mineral Co
5. A-711
6. Philippi District
7. Barbour, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10647
2. 47-001-00918
3. 103
4. Allegheny Land & Mineral Co
5. A-707
6. Union
7. Barbour WV
8. 26.3 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10648
2. 47-109-03620
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co. #108—018160
6. Logan Wyoming
7. Wyoming, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10649
2. 47-109-00366
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co. #110—018700
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10650
2. 47-109-00372
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co. #117—019120
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10651
2. 47-109-00374
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co. #118—019320
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10652
2. 47-109-00200
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #9—014530
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10653
2. 47-005-00994
3. 108
4. Ashland Exploration Inc
5. Southern Land Co #2—044980
6. Logan Wyoming
7. Boone, WV
8. 9.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10654
2. 47-109-00204
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #10—014550
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10655
2. 47-109-00254
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #14—015150
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10656
2. 47-109-00249
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #13—014879
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10657
2. 47-109-00217
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #12—014630
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10658
2. 47-109-00216
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #11—014620
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp

1. 79-10659
2. 47-109-00190
3. 108
4. Ashland Exploration Inc
5. Pardee Land Co #8—014490

6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10660
2. 47-035-00424
3. 108
4. Ashland Exploration Inc
5. Elizabeth W Perkins #24—011040
6. New Field
7. Jackson, WV
8. 5.2 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10661
2. 47-035-00408
3. 108
4. Ashland Exploration Inc
5. Elizabeth W Perkins #23—010890
6. New Field
7. Jackson, WV
8. 5.2 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10662
2. 47-039-00253-3000
3. 108
4. Ashland Exploration Inc
5. J A Osborne #2—001340
6. Old Field
7. Kanawha, WV
8. 6.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10663
2. 47-109-00257
3. 108
4. Ashland Exploration Inc
5. W M Ritter Lumber Co #63—015180
6. Logan Wyoming
7. Wyoming, WV
8. 11.9 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10664
2. 47-039-02516
3. 108
4. Ashland Exploration Inc
5. J A Osborne #11—001430
6. Old Field
7. Kanawha, WV
8. 6.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10665
2. 47-035-00406
3. 108
4. Ashland Exploration Inc
5. Elizabeth W Perkins #21—010870
6. New Field
7. Jackson, WV
8. 5.2 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10666
2. 47-035-00374
3. 108
4. Ashland Exploration Inc
5. Elizabeth W Perkins #18—010650
6. New Field
7. Jackson, WV
8. 5.2 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10667
2. 47-035-00342
3. 108
4. Ashland Exploration Inc
5. Elizabeth W Perkins #17—010610
6. New Field
7. Jackson, WV
8. 5.2 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10668
2. 47-035-00289
3. 108
4. Ashland Exploration Inc
5. Elizabeth W Perkins #13—010490
6. New Field
7. Jackson, WV
8. 5.2 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10669
2. 47-035-00262
3. 108
4. Ashland Exploration Inc
5. Elizabeth W Perkins #12—010180
6. New Field
7. Jackson, WV
8. 5.2 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10670
2. 47-005-00689
3. 108
4. Ashland Exploration Inc
5. Siler Coal Land Co Fee #26—012320
6. Siler
7. Boone, WV
8. 5.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10671
2. 47-005-00688
3. 108
4. Ashland Exploration Inc
5. Siler Coal Land Co Fee #25—012300
6. Siler
7. Boone, WV
8. 5.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10672
2. 47-005-00687
3. 108
4. Ashland Exploration Inc
5. Siler Coal Land Co Fee #24—012290
6. Siler
7. Boone, WV
8. 5.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp
1. 79-10673
2. 47-005-00677
3. 108
4. Ashland Exploration Inc.
5. Siler Coal Land Co. fee #23-011980
6. Siler
7. Boone, WV
8. 5.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.
1. 79-10674
2. 47-005-00670
3. 108
4. Ashland Exploration Inc.
5. Siler Coal Land Co. Fee #22-011970
6. Siler
7. Boone, WV
8. 5.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.
1. 79-10675
2. 47-109-00231
3. 108
4. Ashland Exploration Inc.
5. W. M. Ritter Lumber Co. #55-014770
6. Logan Wyoming
7. Wyoming, WV
8. 7.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.
1. 79-10676
2. 47-109-00227
3. 108
4. Ashland Exploration Inc.
5. W. M. Ritter Lumber Co. #54-014670
6. Logan Wyoming
7. Wyoming, WV
8. 11.9 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.
1. 79-10677
2. 47-109-00210
3. 108
4. Ashland Exploration Inc.
5. W. M. Ritter Lumber Co. #53-014580
6. Logan Wyoming
7. Wyoming, WV
8. 7.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.
1. 79-10678
2. 47-109-00205
3. 108
4. Ashland Exploration Inc.
5. W. M. Ritter Lumber Co. #51-014510
6. Logan Wyoming
7. Wyoming, WV
8. 2.4 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.
1. 79-10679
2. 47-109-00206
3. 108
4. Ashland Exploration Inc.
5. W. M. Ritter Lumber Co. #52-14560
6. Logan Wyoming
7. Wyoming, WV
8. 7.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.
1. 79-10680
2. 47-109-00196
3. 108
4. Ashland Exploration Inc.
5. W. M. Ritter Lumber Co. #50-014500
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.
1. 79-10681
2. 47-109-00186
3. 108
4. Ashland Exploration Inc.
5. W. M. Ritter Lumber Co. #40-014410
6. Logan Wyoming

7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10682
2. 47-109-00182
3. 108
4. Ashland Exploration Inc.
5. W. M. Ritter Lumber Co. #48-014390
6. Logan Wyoming
7. Wyoming, WV
8. 5.5 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10683
2. 47-109-00179
3. 108
4. Ashland Exploration Inc.
5. W. M. Ritter Lumber Co. #47-014380
6. Logan Wyoming
7. Wyoming, WV
8. 7.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10684
2. 47-045-00194
3. 108
4. Ashland Exploration Inc.
5. W. M. Ritter Lumber Co. #61-014860
6. Logan Wyoming
7. Logan, WV
8. 10.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10685
2. 47-039-00279
3. 108
4. Ashland Exploration Inc.
5. J. A. Osborne #4-001360
6. Old Field
7. Kanawha, WV
8. 6.1 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10686
2. 47-041-02490
3. 103
4. Allegheny Land & Mineral Co.
5. A-703
6. Court House District
7. Lewis; WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10687
2. 47-033-01095
3. 103
4. Allegheny Land & Mineral Co.
5. A-674
6. Union District
7. Harrison, WV
8. 38.2 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10688
2. 47-017-01868
3. 103
4. Allegheny Land & Mineral Co.
5. A-679
6. Southwest District
7. Doddridge, WV
8. 25.9 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10689
2. 47-091-00139
3. 103
4. Allegheny Land & Mineral Co.
5. A-743
6. Knottsville District
7. Taylor, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10690
2. 47-033-01259
3. 103
4. Allegheny Land & Mineral Co.
5. A-742
6. Sardis Dist
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10691
2. 47-017-01881
3. 103
4. Allegheny Land & Mineral Co.
5. A-664
6. Southwest District
7. Doddridge, WV
8. 27.8 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10692
2. 47-103-00619
3. 103
4. Allegheny Land & Mineral Co.
5. A-663
6. Grant Dist
7. Wetzel, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10693
2. 47-083-00216
3. 103
4. Allegheny Land & Mineral Co.
5. A-715
6. Middle Fork District
7. Randolph, WV
8. 39.3 million cubic feet
9. June 25, 1979
10. Columbia Gas Transmission Corp.

1. 79-10694
2. 47-049-00327
3. 103
4. Allegheny Land & Mineral Co.
5. A-698
6. Lincoln District
7. Marion, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10695
2. 47-033-01182
3. 103
4. Allegheny Land & Mineral Co.
5. A-697
6. Sardis District
7. Harrison, WV
8. 24.0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10696
2. 47-033-01089
3. 103
4. Allegheny Land & Mineral Co.
5. A-673
6. Union District
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10697
2. 47-033-01014
3. 103
4. Allegheny Land & Mineral Co.
5. A-637
6. Sardis Dist
7. Harrison, WV
8. 52.4 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10698
2. 47-041-02521
3. 103
4. Allegheny Land & Mineral Co.
5. A-765
6. Hackus Creek District
7. Lewis, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10699
2. 47-097-01853
3. 103
4. Allegheny Land & Mineral Co.
5. A-768
6. Washington District
7. Upshur, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10700
2. 47-033-01964
3. 103
4. Allegheny Land & Mineral Co.
5. A-682
6. Union District
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10701
2. 47-107-01962
3. 103
4. Allegheny Land & Mineral Co.
5. A-683
6. Union District
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10702
2. 47-033-01993
3. 103
4. Allegheny Land & Mineral Co.
5. A-684
6. Ten Mile District
7. Harrison, WV
8. .0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10703
2. 47-033-01700
3. 103
4. Allegheny Land & Mineral Co.
5. A-752
6. Sardis District
7. Harrison, WV
8. .0 million cubic feet

9. June 25, 1979
10. Consolidated Gas Supply Corp.

1. 79-10704
2. 47-033-01253
3. 103
4. Allegheny Land & Mineral Co.
5. A-750
6. Union District
7. Harrison, WV
8. 40.0 million cubic feet
9. June 25, 1979
10. Consolidated Gas Supply Corp.

U.S. Geological Survey, Metairie, La.

1. Control Number (F.E.R.C./State)
2. API Well Number
3. Section of NGPA
4. Operator
5. Well name
6. Field or OCS area name
7. County, State or Block No.
8. Estimated annual volume
9. Date received at FERC
10. Purchaser(s)

1. 79-073128
2. 17-712-40105-0000-0
3. 102
4. CNG Producing Company
5. A-10D2
6. Ship Shoal
7. 246000
8. 1095.0 million cubic feet
9. May 18, 1979
10. Consolidated Gas Supply Corporation

U.S. Geological Survey, Casper, Wyo.

1. Control Number (F.E.R.C./State)
2. API Well Number
3. Section of NGPA
4. Operator
5. Well name
6. Field or OCS area name
7. County, State or Block No.
8. Estimated annual volume
9. Date received at FERC
10. Purchaser(s)

1. 79-09337B
2. 43-047-30378-0000-0
3. 103
4. Gas Producing Enterprises Inc
5. NBU 7-9B 30378
6. Natural Buttes Unit
7. Unitah, UT
8. 40.0 million cubic feet
9. June 29, 1979
10. Colorado Interstate Gas Co

1. 79-09337C
2. 43-047-30444-0000-0
3. 103
4. Gas Producing Enterprises Inc
5. NBU 64-24B 30444
6. Natural Buttes Unit
7. Unitah, UT
8. 10.0 million cubic feet
9. June 19, 1979
10. Colorado Interstate Gas Co

1. 79-09961
2. 05-103-81410-0000-5
3. 103
4. Continental Oil Company
5. Dragon Trail #46
6. Douglas Creek NW 21-T2S-R102W
7. Rio Blanco, CO
8. 146.0 million cubic feet
9. June 21, 1979
10. Western Slope Gas Company

The applications for determination in these proceedings together with a copy or description of other materials in the record on which such determinations were made are available for inspection, except to the extent such material is treated as confidential under 18 CFR 275.206, at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Persons objecting to any of these final determinations may, in accordance with 18 CFR 275.203 and 18 CFR 275.204, file a protest with the Commission within fifteen (15) days of the date of publication of this notice in the Federal Register.

Please reference the FERC control number in all correspondence related to these determinations.

Kenneth F. Plumb,
Secretary.

[FR Doc. 79-22644 Filed 7-20-79; 8:45 am]
BILLING CODE 6450-01-M

[Docket No. CP79-378]

Washington Gas Light Co., Application for Exemption

July 16, 1979.

Take notice that on June 21, 1979, Washington Gas Light Company (Washington), 1100 H Street, N.W., Washington, D.C. 20080, filed in Docket No. CP79-378 an application pursuant to Section 1(c) of the Natural Gas Act for exemption from the provisions of the Natural Gas Act and the regulations of the Commission thereunder of a proposed new natural gas service in Shenandoah County, Virginia, all as more fully set forth in the application on file with the Commission and open to public inspection.

Washington currently operates a service area involving the Commonwealth of Virginia, the State of Maryland and the District of Columbia, pursuant ot Section 7(f) of the Natural Gas Act.

Washington proposes to initiate a new natural gas service in Shenandoah County, which service would be rendered in a separate and distinct area from that authorized under Section 7(f). Washington indicates that it would purchase and receive the gas necessary to provide the natural gas service from Columbia Gas Transmission Corporation (Columbia) at a new delivery point [1] to be constructed near Coffmantown, Virginia, and State Routes 679 and 680 in the Stonewall District of Shenandoah County. Washington proposes to transport the gas 4.5 miles through its proposed pipeline for sale to the Johns-Manville Sales Corporation [2] solely within Shenandoah County. Therefore, Washington indicates, that all of the gas which it would receive from Columbia would be received and ultimately consumed within Virginia.

Any person desiring to be heard or to make any protest with reference to said application should on or before August 7, 1979, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petition to intervene in accordance with the Commission's Rules.

Kenneth F. Plumb,
Secretary.

[FR Doc. 79-22636 Filed 7-20-79; 8:45 am]
BILLING CODE 6450-01-M

[1] Columbia has filed for authorization in Docket No. CP79-334 to construct the mainline tap and measuring facilities for the proposed delivery point to Washington.

[2] Washington states that the service which it proposes to provide for Johns-Manville Sales Corporation would be an interruptible service at a rate of 3,500 dekatherms (dt) per year.

[Docket No. CP74-177]

Washington Natural Gas Co., as Project Operator; Petition To Amend

July 13, 1979.

Take notice that on June 19, 1979, Washington Natural Gas Company (Washington Natural), 815 Mercer Street, Seattle, Washington 98111, filed in Docket No. CP74-177 a petition to amend the order of July 29, 1974, as amended, in the instant docket (52 FPC 236) [1] pursuant to Section 7(c) of the Natural Gas Act so as to authorize the continuation of the testing and development program for a new storage zone (Zone 9) in the Jackson Prairie Storage Project), an underground, aquifer-type natural gas storage facility, in Lewis County, Washington, for three additional years, through December 31, 1982, all as more fully set forth in the petition to amend on file with the

[1] This proceeding was commenced before the FPC. By joint regulation of October 1, 1944 (10 CFR 1000.1), it was transferred to the Commission.

Commission and open to public inspection.

Pursuant to authorization granted in Docket No. CP71-7, Washington Natural was granted authorization to begin development of the storage capability of Zone 9; and pursuant to the order of July 29, 1974, as amended, in the instant docket, Washington Natural, as project operator, was granted budget-type authorization to develop further Zone 9 and to continue the testing program of the zone through December 31, 1979. Since 1972 wells have been drilled in Zone 9 for testing purposes, Washington Natural indicates, and geologic data obtained from the testing show that a portion of the Zone 9 reservoir is potentially suitable for gas storage. Washington Natural states that gas injection operations utilizing the test wells have also produced positive results, with favorable wellhead injection pressures and pressure responses in observation wells. The primary problem encountered in the testing, according to Washington Natural, has been the high water content during gas withdrawal cycles. Washington Natural proposes to overcome this problem by drying out the potentially useful portion of the Zone 9 reservoir through a further series of injection-withdrawal cycles. In order to afford time for this process, Washington Natural requests authorization to continue the testing and development of Zone 9 for three additional years.

Any person desiring to be heard or to make any protest with reference to said petiton to amend should on or before August 2, 1979, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a part to a proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petiton to intervene in accordance with the Commission's Rules.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22637 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-504]

Washington Water Power Co.; Notice of Tender of "Letter Agreement"

July 17, 1979.

The filing Company submits the following: Take notice that on July 10, 1979, The Washington Water Power Company (Washington) tendered for filling copies of a service schedule applicable to what Washington refers to as a "Letter Agreement" between Washington and Southern California Edison Company (Edison), which applies to the exchange of capacity. Washington states that the capacity will be delivered to Edison during July and August 1979 and Edison will deliver capacity to Washington during December 1983, January and February 1984.

Washington requests that the requirements of prior notice be waived and the effective date be made retroactive to July 1, 1979, adding that there would be no effect upon purchases under other rate schedules.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before August 7, 1979. Protest will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-22638 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

Determinations by Jurisdictional Agencies Under the natural Gas Policy Act of 1978

July 12, 1979.

The Federal Energy Regulatory Commission received notices from the jurisdictional agencies listed below of determinations pursuant to 18 CFR 274.104 and applicable to the indicated wells pursuant to the Natural Gas Policy Act of 1978.

Louisiana Office of Conservation

1. Control Number (F.E.R.C./State)
2. API Well Number
3. Section of NGPA
4. Operator
5. Well name
6. Field or OCS area name
7. County, State or Block No
8. Estimated annual volume
9. Date received at FERC
10. Purchaser(s)

1. 79-11315
2. 17-075-22469-
3. 102
4. Gulf Oil Corporation
5. S L 195 QQ No 284
6. Quarantine Bay
7. Plaquemines, La
8. 51.0 million cubic feet
9. June 28, 1979
10. United Gas Pipeline Co

1. 79-11316
2. 17-057-21524-
3. 102
4. Gulf Oil Corporation
5. S L PP 192 No 277
6. Timbalier Bay
7. LaFourche, La
8. 55.0 million cubic feet
9. June 28, 1979
10. Tennessee Gas Pipeline Co

1. 79-11317
2. 17-057-21511-
3. 102
4. Gulf Oil Corporation
5. S L PP 192 No 276
6. Timbalier Bay
7. LaFourche, La
8. 73.0 million cubic feet
9. June 28, 1979
10. Tennessee Gas Pipeline Co

1. 79-11318
2. 17-057-21520-
3. 102
4. Gulf Oil Corporation
5. Delta Securities Co Inc Well No 127
6. Bully Camp
7. LaFourche, La
8. 50.0 million cubic feet
9. June 28, 1979
10. Tennessee Gas Pipeline Co

1. 79-11319
2. 17-127-20643-
3. 102
4. Justiss-Mears Oil Company Inc
5. WX RA VU A Pardee 1
6. Hattaway Branch
7. Winn, La
8. 9.0 million cubic feet
9. June 28, 1979
10. United Gas Pipe Line Co

1. 79-11320
2. 17-109-21900-
3. 102
4. Pennzoil Producing Company
5. VU C State Bay Baptiste No 6-D
6. Bay Baptiste
7. Terrebonne, La
8. 100.0 million cubic feet

9. June 28, 1979
10. United Gas Pipe Line Company

1. 79-11321
2. 17-109-21958-
3. 102
4. Pennzoil Producing Company
5. VU C State Bay Baptiste No 9
6. Bay Baptiste
7. Terrebonne, La
8. 75.0 million cubic feet
9. June 28, 1979
10. United Gas Pipe Line Company

1. 79-11322
2. 17-109-21900-
3. 102
4. Pennzoil Producing Company
5. VU C State Bay Baptiste No 8
6. Bay Baptiste
7. Terrebonne, La
8. 40.0 million cubic feet
9. June 28, 1979
10. United Gas Pipe Line Company

1. 79-11323
2. 17-109-22038-
3. 102
4. Texaco Inc
5. VUL DGL U-12 No 55
6. Dog Lake
7. Terrebonne, La
8. 99.6 million cubic feet
9. June 28, 1979
10. Texas Gas Transmission Corp

Ohio Department of Natural Resources, Division of Oil and Gas

1. Control Number (F.E.R.C./State)
2. API well number
3. Section of NGPA
4. Operator
5. Well name
6. Field or OCS area name
7. County, State or Block No
8. Estimated annual volume
9. Date received at FERC
10. Purchaser(s)

1. 79-11141
2. 34-157-21810-0014-
3. 108
4. The Mutual Oil & Gas Company
5. Deward Herron No. 1-A
6.
7. Tuscarawas, OH
8. 3.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11142
2. 34-121-21151-0014-
3. 108
4. Craig Cleary
5. Roy Graham No 1
6.
7. Noble, OH
8. 2.3 million cubic feet
9. June 27, 1979
10. Columbia Gas Trans

1. 79-11143
2. 34-121-21249-0014-
3. 108
4. Craig Cleary
5. J Fletcher Guiler No 2
6.
7. Noble, OH
8. 2.0 million cubic feet
9. June 27, 1979
10. Columbia Gas Trans

1. 79-11144
2. 34-121-21238-0014-
3. 108
4. Craig Cleary
5. Craig Cleary No 1
6.
7. Noble, OH
8. 1.3 million cubic feet
9. June 27, 1979
10. Columbia Gas Trans

1. 79-11145
2. 34-121-21293-0014-
3. 108
4. Craig Cleary
5. Craig Cleary No 2
6.
7. Noble, OH
8. 1.2 million cubic feet
9. June 27, 1979
10. Columbia Gas Trans

1. 79-11146
2. 34-121-20411-0014-
3. 108
4. Craig Cleary
5. I C Johnson No 1
6.
7. Noble, OH
8. .5 million cubic feet
9. June 27, 1979
10. Columbia Gas Trans

1. 79-11147
2. 34-121-21136-0014-
3. 108
4. Craig Cleary
5. J F & V K Guiler No 1
6.
7. Noble, OH
8. 2.0 million cubic feet
9. June 27, 1979
10. Columbia Gas Trans

1. 79-11148
2. 34-121-20285-0014-
3. 108
4. Craig Cleary
5. Pluma Spence No 1
6.
7. Noble, OH
8. 1.3 million cubic feet
9. June 27, 1979
10. Columbia Gas Trans

1. 79-11149
2. 34-121-20454-0014-
3. 108
4. Craig Cleary
5. Frank Bates No 1
6.
7. Noble, OH
8. .5 million cubic feet
9. June 27, 1979
10. Columbia Gas Trans

1. 79-11150
2. 34-009-21809-0014
3. 108
4. Poston Operation Co. Inc.
5. Millfield No. 5
6.
7. Athens, OH
8. 1.3 million cubic feet
9. June 27, 1979
10. Columbia Gas Transmission Corp.

1. 79-11151
2. 34-121-20570-0014
3. 108
4. Gould Ward
5. Ward Gas Syndicate No. 1
6.
7. Noble, OH
8. 2.0 million cubic feet
9. June 27, 1979
10. Columbia Gas Trans.

1. 79-11152
2. 34-121-21685-0014
3. 108
4. St. Joe Petroleum (US) Corporation
5. Herman Veagle No. 1
6. Undesignated
7. Noble, OH
8. 8.0 million cubic feet
9. June 27, 1979
10. Republic Steel Corporation

1. 79-11153
2. 34-019-20591-0014
3. 108
4. MB Operation Co. Inc.
5. James-Carl No. 2
6.
7. Carroll, OH
8. 3.3 million cubic feet
9. June 27, 1979
10. East Ohio Gas Co., Republic Steel Corporation, Columbia Gas Company

1. 79-11154
2. 34-019-20581-0014
3. 108
4. MB Operating Co. Inc.
5. James-Carl No. 3
6.
7. Carroll, OH
8. 3.3 million cubic feet
9. June 27, 1979
10. East Ohio Gas Co., Republic Steel Corporation, Columbia Gas Company

1. 79-11155
2. 34-019-20298-0014
3. 108
4. MB Operating Co. Inc.
5. James Sisters No. 1
6.
7. Carroll, OH
8. 3.7 million cubic feet
9. June 27, 1979
10. East Ohio Gas Co., Republic Steel Corporation, Columbia Gas Company

1. 79-11156
2. 34-073-21892-0014
3. 108
4. Orwig Oil Company
5. Edward St. Clair No. 2
6.
7. Hocking, OH
8. 1.0 million cubic feet
9. June 27, 1979
10. Paramount Transmission Corp.

1. 79-11157
2. 34-073-21927-0014
3. 108
4. Orwig Oil Company
5. Charles Struble No. 2
6.
7. Hocking, OH
8. 3.0 million cubic feet
9. June 27, 1979
10. Paramount Transmission Corp.

1. 79-11158
2. 34-073-21767-0014
3. 108

4. Orwig Oil Company
5. Donald Wahl No. 1
6.
7. Hocking, OH
8. 1.8 million cubic feet
9. June 27, 1979
10. Paramount Transmission Corp.

1. 79-11159
2. 34-073-21795-0014
3. 108
4. Orwig Oil Company
5. Helen Inboden No. 1
6.
7. Hocking, OH
8. 2.8 million cubic feet
9. June 27, 1979
10. Paramount Transmission Corp.

1. 79-11160
2. 34-073-21800-0014
3. 108
4. Orwig Oil Company
5. Donald Wahl No. 2
6.
7. Hocking, OH
8. 1.8 million cubic feet
9. June 27, 1979
10. Paramount Transmission Corp.

1. 79-11161
2. 34-121-21686-0014
3. 108
4. St. Joe Petroleum (US) Corporation
5. H Mitchell No. 1
6. Undesignated
7. Noble, OH
8. 11.0 million cubic feet
9. June 27, 1979
10. Republic Steel Corporation

1. 79-11162
2. 34-121-21980-0014
3. 108
4. St. Joe Petroleum (US) Corporation
5. R. Schell No. 1
6. Undesignated
7. Noble, OH
8. 8.0 million cubic feet
9. June 27, 1979
10. Republic Steel Corporation

1. 79-11163
2. 34-121-21778-0014
3. 108
4. St. Joe Petroleum (US) Corporation
5. J. Noon No. 2
6. Undesignated
7. Noble, OH
8. 8.0 million cubic feet
9. June 27, 1979
10. Republic Steel Corporation

1. 79-11164
2. 34-059-21792-0014
3. 108
4. St. Joe Petroleum (US) Corporation
5. J. Jenkins No. 1
6. Undesignated
7. Guernsey, OH
8. 5.0 million cubic feet
9. June 27, 1979
10. Republic Steel Corporation

1. 79-11165
2. 34-121-21746-0014
3. 108
4. St. Joe Petroleum (US) Corporation
5. V. Moore No. 2
6. Undesignated
7. Noble, OH
8. 10.0 million cubic feet
9. June 27, 1979
10. Republic Steel Corporation

1. 79-11166
2. 34-157-22104-0014
3. 108
4. The Mutual Oil & Gas Company
5. T. Herron Unit No. 1
6.
7. Tuscarawas, OH
8. 13.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11167
2. 34-157-21759-0014
3. 108
4. The Mutual Oil & Gas Company
5. Wilmer Kaderly (David M. Seikel) No. 1
6.
7. Tuscarawas, OH
8. 12.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11168
2. 34-157-21818-0014
3. 108
4. The Mutual Oil & Gas Company
5. Kaderly-Seikel No. 2
6.
7. Tuscarawas, OH
8. 17.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11169
2. 34-157-21144-0014
3. 108
4. The Mutual Oil & Gas Company
5. Leatherman No. 1
6.
7. Tuscarawas, OH
8. 8.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11170
2. 34-157-21765-0014
3. 108
4. The Mutual Oil & Gas Company
5. Everhard-Cole No. 3
6.
7. Tuscarawas, OH
8. 5.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11171
2. 34-157-21305-0014
3. 108
4. The Mutual Oil & Gas Company
5. John B. Fait No. 1
6.
7. Tuscarawas, OH
8. 5.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11172
2. 34-157-22461-0014
3. 108
4. The Mutual Oil & Gas Company
5. Arthur D. & Mary F. Kage No. 1
6.
7. Tuscarawas, OH
8. 12.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11173
2. 34-151-22526-0014
3. 108
4. Pominex Inc.
5. No. 1 Frederick
6.
7. Stark, OH
8. 1.9 million cubic feet
9. June 27, 1979
10. Columbia Gas Transmission Corp., Columbia Gas of Ohio

1. 79-11174
2. 34-151-22560-0014
3. 108
4. Pominex Inc.
5. No. 2 Gabric U.
6.
7. Stark, OH
8. 1.6 million cubic feet
9. June 27, 1979
10. Columbia Gas Transmission Corp., Columbia Gas of Ohio

1. 79-11175
2. 34-151-22557-0014
3. 108
4. Pominex Inc.
5. No. 1 Mary Monter U.
6.
7. Stark, OH
8. 5.4 million cubic feet
9. June 27, 1979
10. Columbia Gas Transmission Corp., Columbia Gas of Ohio

1. 79-11176
2. 34-151-22540-0014
3. 108
4. Pominex Inc.
5. N. Hadinger No. 1
6.
7. Stark, OH
8. 2.0 million cubic feet
9. June 27, 1979
10. East Ohio Gas Co.

1. 79-11177
2. 34-151-22529-0014
3. 108
4. Pominex Inc.
5. Oyster No. 1
6.
7. Stark, OH
8. 2.0 million cubic feet
9. June 27, 1979
10. East Ohio Gas Co.

1. 79-11178
2. 34-151-22548-0014
3. 108
4. Pominex Inc
5. #1 C Johnson
6.
7. Stark, OH
8. 8.0 million cubic feet
9. June 27, 1979
10. Columbia Gas Transmission Corp., Columbia Gas of Ohio

1. 79-11179
2. 34-151-22594-0014
3. 108
4. Pominex Inc
5. #1 Van Wagenen U
6.
7. Stark, OH
8. 8.4 million cubic feet
9. June 27, 1979

10. Columbia Gas Transmission Corp., Columbia Gas of Ohio

1. 79-11180
2. 34-151-22545-0014
3. 108
4. Pominex Inc
5. #1 May
6.
7. Stark, OH
8. 3.1 million cubic feet
9. June 27, 1979
10. Columbia Gas Transmission Corp., Columbia Gas of Ohio

1. 79-11181
2. 34-163-20394-0014
3. 103
4. Inland Drilling Co Inc.
5. Jay Mar Coal Co Sentry Royalty #4 03
6.
7. Vinton, OH
8. .4 million cubic feet
9. June 27, 1979
10.

1. 79-11182
2. 34-127-24252-0014
3. 103
4. American Well Management Company
5. Shrider #1
6.
7. Perry, OH
8. 18.0 million cubic feet
9. June 27, 1979
10.

1. 79-11183
2. 34-127-24251-0014
3. 103
4. American Well Management Company
5. Love No 1
6.
7. Perry, OH
8. 18.0 million cubic feet
9. June 27, 1979
10.

1. 79-11184
2. 34-151-21788-0014
3. 108
4. Jerry Moore Inc
5. NATCO Corporation #14
6. East Canton
7. Stark, OH
8. 12.0 million cubic feet
9. June 27, 1979
10. East Ohio Gas Company

1. 79-11185
2. 34-121-21638-0014
3. 108
4. Allegheny Land & Mineral Company
5. Boyd Well-AO-2
6.
7. Noble, OH
8. 6.0 million cubic feet
9. June 27, 1979
10. East Ohio Gas Company

1. 79-11186
2. 34-121-21641-0014
3. 108
4. Allegheny Land & Mineral Company
5. Franklin Well-AO-3
6.
7. Noble, OH
8. 17.0 million cubic feet
9. June 27, 1979
10. East Ohio Gas Company

1. 79-11187
2. 34-121-21649-0014
3. 108
4. Allegheny Land & Mineral Company
5. Smith Well-AO-5
6.
7. Noble, OH
8. 2.0 million cubic feet
9. June 27, 1979
10. East Ohio Gas Company

1. 79-11188
2. 34-121-21668-0014
3. 108
4. Allegheny Land & Mineral Company
5. Gordon Well-AO-7
6.
7. Noble, OH
8. 7.0 million cubic feet
9. June 27, 1979
10. East Ohio Gas Company

1. 79-11189
2. 34-059-21139-0014
3. 108
4. Appalachian Exploration Inc
5. Lucag-Love #1
6.
7. Guernsey, OH
8. 3.0 million cubic feet
9. June 27, 1979
10. Columbia Gas Transmission Corp

1. 79-11190
2. 34-157-21821
3. 108
4. The Mutual Oil & Gas Company
5. D E Herron #2-A
6.
7. Tuscarawas, OH
8. 3.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11191
2. 34-157-22731-0014
3. 108
4. K S T Oil & Gas Co Inc
5. Beaber #1
6.
7. Tuscarawas, OH
8. 12.0 million cubic feet
9. June 27, 1979
10. East Ohio Gas Co

1. 79-11192
2. 34-075-21832-0014
3. 108
4. Amtex Oil And Gas Inc
5. Briar Hill Stone No 1
6.
7. Holmes, OH
8. 30.0 million cubic feet
9. June 27, 1979
10. Columbia Gas Transmission Corp

1. 79-11193
2. 34-157-21657-0014
3. 108
4. The Mutual Oil & Gas Company
5. Harrison Leasing Co #1
6.
7. Tuscarawas, OH
8. 7.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11194
2. 34-157-21930-0014
3. 108
4. The Mutual Oil & Gas Company
5. Harrison Leasing Co #2
6.
7. Tuscarawas, OH
8. 7.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11195
2. 34-157-21071-0014
3. 108
4. The Mutual Oil & Gas Company
5. Glass Comm Well #1
6.
7. Tuscarawas, OH
8. 14.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11196
2. 34-157-21912-0014
3. 108
4. The Mutual Oil & Gas Company
5. A F Glass #1-A
6.
7. Tuscarawas, OH
8. 9.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11197
2. 34-151-22439-0014
3. 108
4. MB Operating Co Inc
5. R & C Oyer Unit #1
6.
7. Stark, OH
8. 10.2 million cubic feet
9. June 27, 1979
10. East Ohio Gas Company, Republic Steel Corporation, Columbia Gas Company

1. 79-11198
2. 34-151-22553-0014
3. 108
4. Pominex Inc
5. #1 Donald Rohr
6.
7. Stark, OH
8. 1.9 million cubic feet
9. June 27, 1979
10. Columbia Gas Transmission Corp, Columbia Gas of Ohio

1. 79-11199
2. 34-151-22533-0014
3. 108
4. Pominex Inc
5. F Johnson #1
6.
7. Stark, OH
8. 2.7 million cubic feet
9. June 27, 1979
10. Columbia Gas Transmission Corp, Columbia Gas of Ohio

1. 79-11200
2. 34-151-22544-0014
3. 108
4. Pominex Inc
5. #1 Brieske
6.
7. Stark, OH
8. 3.1 million cubic feet
9. June 27, 1979
10. Columbia Gas Transmission Corp, Columbia Gas of Ohio

1. 79-11201
2. 34-157-21162-0014
3. 108
4. The Mutual Oil & Gas Company

5. Leatherman #2
6.
7. Tuscarawas, OH
8. 7.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11202
2. 34-157-22345-0014
3. 108
4. The Mutual Oil & Gas Company
5. George Ray Leggett #1
6.
7. Tuscarawas, OH
8. 20.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11203
2. 34-157-21762-0014
3. 108
4. The Mutual Oil & Gas Company
5. L Lamport #1
6.
7. Tuscarawas, OH
8. 15.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

1. 79-11204
2. 34-157-21183-0014
3. 108
4. The Mutual Oil & Gas Company
5. Leatherman #1
6.
7. Tuscarawas, OH
8. 7.0 million cubic feet
9. June 27, 1979
10. The East Ohio Gas Company

West Virginia Department of Mines, Oil and Gas Division

1. Control Number (FERC/State)
2. API well number
3. Section of NGPA
4. Operator
5. Well name
6. Field or OCS area name
7. County, State or block No.
8. Estimated Annual Volume
9. Date Received at FERC
10. Purchaser(s)

1. 79-11275
2. 47-033-01105
3. 108
4. Allegheny Land & Mineral Co.
5. A-670
6. Sardis District
7. Harrison, WV
8. 17.9 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11276
2. 47-033-01052
3. 108
4. Allegheny Land & Mineral Co.
5. A-658
6. Sardis District
7. Harrison, WV
8. 4.6 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11277
2. 47-097-01509
3. 108
4. Allegheny Land & Mineral Co
5. A-499
6. Union District
7. Upshur, WV
8. 8.1 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11278
2. 47-041-01529
3. 108
4. Allegheny Land & Mineral Company
5. A-327
6. Hackers Creek District
7. Lewis, WV
8. 5.0 million cubic feet
9. June 28, 1979
10. Equitable Gas

1. 79-11279
2. 47-041-01531
3. 108
4. Allegheny Land & Mineral Company
5. A-328
6. Hackers Creek District
7. Lewis, WV
8. 5.0 million cubic feet
9. June 28, 1979
10. Equitable Gas

1. 79-11280
2. 47-041-01540
3. 108
4. Allegheny Land & Mineral Company
5. A-329
6. Hackers Creek District
7. Lewis, WV
8. 2.3 million cubic feet
9. June 28, 1979
10. Equitable Gas

1. 79-11281
2. 47-033-01026
3. 108
4. Allegheny Land & Mineral Co
5. A-630
6. Union District
7. Harrison, WV
8. 16.1 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11282
2. 47-041-01541
3. 108
4. Allegheny Land & Mineral Company
5. A-330
6. Hackers Creek District
7. Lewis, WV
8. 1.1 million cubic feet
9. June 28, 1979
10. Equitable Gas

1. 79-11283
2. 47-041-00496
3. 108
4. Allegheny Land & Mineral Co
5. A-79
6. Freemans Creek District
7. Lewis, WV
8. 3.4 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11284
2. 47-021-01467
3. 108
4. Allegheny Land & Mineral Co
5. A-198
6. Glenville District
7. Gilmer, WV
8. 4.2 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11285
2. 47-041-00466
3. 108
4. Allegheny Land & Mineral Co
5. A-69
6. Freemans Creek District
7. Lewis, WV
8. 1.0 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11286
2. 47-017-00885
3. 108
4. Allegheny Land & Mineral Co
5. A-201
6. Grant District
7. Doddridge, WV
8. .2 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11287
2. 47-013-01789
3. 108
4. Allegheny Land & Mineral Co
5. A-68
6. Washington District
7. Calhoun, WV
8. 1.7 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11288
2. 47-017-00855
3. 108
4. Allegheny Land & Mineral Co
5. A-194
6. McClellon District
7. Doddridge, WV
7. 2.5 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11289
2. 47-041-00598
3. 108
4. Allegheny Land & Mineral Co
5. A-64
6. Court House District
7. Lewis, WV
8. 3.3 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11290
2. 47-017-00502
3. 108
4. Allegheny Land & Mineral Co
5. A-99
6. Grand District
7. Doddridge, WV
8. 5.3 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11291
2. 47-033-01106
3. 108
4. Allegheny Land & Mineral Co
5. A-672
6. Sardis District
7. Harrison, WV
8. 7.0 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11292
2. 47-033-01112

3. 108
4. Allegheny Land & Mineral Co
5. A-676
6. Union District
7. Harrison, WV
8. 21.6 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11293
2. 47-017-00243
3. 108
4. Allegheny Land & Mineral Co
5. A-5
6. Central District
7. Doddridge, WV
8. .8 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11294
2. 47-085-01866
3. 108
4. Allegheny Land & Mineral Co
5. A-6
6. Union District
7. Ritchie, WV
8. 4.2 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11294
2. 47-085-01945
3. 108
4. Allegheny Land & Mineral Co
5. A-16
6. Union District
7. Ritchie, WV
8. 3.2 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11296
2. 47-017-01864
3. 108
4. Allegheny Land & Mineral Co
5. A-667
6. Southwest District
7. Doddridge, WV
8. 9.3 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11297
2. 47-041-01182
3. 108
4. Allegheny Land & Mineral Co
5. A-223
6. Court House District
7. Lewis, WV
8. 4.9 million cubic feet
9. June 28, 1979
10. Equitable Gas

1. 79-11298
2. 47-097-01577
3. 108 Denied
4. Allegheny Land & Mineral Co
5. A-512
6. Washington District
7. Upshur, WV
8. .2 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11299
2. 47-021-01138
3. 108 Denied
4. Allegheny Land & Mineral Co
5. A-57
6. Appalachian Basin
7. Gilmer WV
8. 2.2 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11300
2. 47-041-00816
3. 108 Denied
4. Allegheny Land & Mineral Co
5. A-110
6. Appalachian Basin
7. Lewis, WV
8. 1.6 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11301
2. 47-041-00793
3. 108
4. Allegheny Land & Mineral Co
5. A-150
6. Court House District
7. Lewis, WV
8. 2.6 million cubic feet
9. June 28, 1979
10. Equitable Gas

1. 79-11367
2. 47-041-01211
3. 108
4. Allegheny Land & Mineral Co
5. A-230
6. Court House District
7. Lewis, WV
8. .7 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11368
2. 47-017-00921
3. 108
4. Allegheny Land & Mineral Co
5. A-203
6. McClellan District
7. Doddridge, WV
8. 5.7 million cubic feet
9. June 28, 1979
10. Consolidated Gas Supply Corp

1. 79-11369
2. 47-041-00577
3. 108
4. Allegheny Land & Mineral Co
5. A-88
6. Freemans Creek District
7. Lewis WV
8. 2.1 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11370
2. 47-071-00567
3. 108
4. Allegheny Land & Mineral Co
5. A-145
6. McClellan District
7. Doddridge WV
8. .6 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11371
2. 47-041-00513
3. 108
4. Allegheny Land & Mineral Co
5. A-78
6. Freemans Creek District
7. Lewis WV
8. 2.9 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11372
2. 47-041-00717
3. 108
4. Allegheny Land & Mineral Co
5. A-135
6. Freemans Creek District
7. Lewis WV
8. 7.8 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11373
2. 47-017-01114
3. 108
4. Allegheny Land & Mineral Co
5. A-239
6. Grant District
7. Doddridge WV
8. 1.1 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11374
2. 47-017-00772
3. 108
4. Allegheny Land & Mineral Co.
5. A-173
6. McClellan District
7. Doddridge WV
8. 7.9 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11375
2. 47-085-03060
3. 108
4. Allegheny Land & Mineral Co
5. A-296
6. Murphy District
7. Ritchie WV
8. 4.4 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11376
2. 47-085-03213
3. 108
4. Allegheny Land & Mineral Co
5. A-335
6. Grant District
7. Ritchie WV
8. 2.0 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11377
2. 47-017-01149
3. 108
4. Allegheny Land & Mineral Co
5. A-253
6. McClellan District
7. Doddridge WV
8. .9 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11378
2. 47-017-01353
3. 108
4. Allegheny Land & Mineral Co
5. A-306
6. McClellan District
7. Doddridge WV
8. 2.6 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11379
2. 47-085-02305
3. 108
4. Allegheny Land & Mineral Co

5. A-120
6. (Murphy-District) Appalachian Basin
7. Ritchie WV
8. 1.5 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11380
2. 47-041-00619
3. 108
4. Allegheny Land & Mineral Co
5. A-108
6. Freemans Creek District
7. Lewis WV
8. 4.1 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11381
2. 47-097-01067
3. 108
4. Allegheny Land & Mineral Co
5. A-338
6. Union District
7. Upshur WV
8. 14.2 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11382
2. 47-017-00638
3. 108
4. Allegheny Land & Mineral Co
5. A-160
6. McClellan District
7. Doddridge WV
8. 6.0 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11383
2. 47-017-00547
3. 108
4. Allegheny Land & Mineral Co
5. A-141
6. Grant District
7. Doddridge WV
8. 6.1 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11384
2. 47-097-01109
3. 108
4. Allegheny Land & Mineral Co
5. A-353
6. Washington District
7. Upshur WV
8. 10.9 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. 79-11385
2. 47-085-02011
3. 108
4. Allegheny Land & Mineral Co
5. A-19
6. Murphy District
7. Ritchie WV
8. 7.5 million cubic feet
9. June 29, 1979
10. Consolidated Gas Supply Corp

1. Control Number (F.E.R.C./State)
2. API Well number
3. Section of NGPA
4. Operator
5. Well name
6. Field or OCS area name
7. County, State or Block No.
8. Estimated annual volume
9. Date received at FERC
10. Purchaser(s)

1. 79-11205
2. 49-005-25086
3. 103
4. Amoco Production Company
5. Springen #1
6. Highlight
7. Campbell WY
8. 330.0 million cubic feet
9. June 27, 1979
10. Phillips Petroleum Corporation

1. 79-11206
2. 49-029-20739
3. 103
4. Amoco Production Company
5. Elk Basin Unit #1—310
6. Elk Basin
7. Park WY
8. 6.0 million cubic feet
9. June 27, 1979
10. Montana-Dakota Utilities Company

1. 79-11207
2. 49-029-20746
3. 103
4. Amoco Production Company
5. Elk Basin Unit #1—311
6. Elk Basin
7. Park WY
8. 10.0 million cubic feet
9. June 27, 1979
10. Montana-Dakota Utilities Company

1. 79-11208
2. 49-029-20738
3. 103
4. Amoco Production Company
5. Elk Basin Unit #1—312
6. Elk Basin
7. Park WY
8. 10.0 million cubic feet
9. June 27, 1979
10. Montana-Dakota Utilities Company

1. 79-11209
2. 49-029-20766
3. 103
4. Amoco Production Company
5. Elk Basin Unit #1—314
6. Elk Basin
7. Park WY
8. 9.0 million cubic feet
9. June 27, 1979
10. Montana-Dakota Utilities Inc

1. 79-11210
2. 49-029-20677
3. 103
4. Amoco Production Company
5. Elk Basin Unit #1—315
6. Elk Basin
7. Park WY
8. 9.0 million cubic feet
9. June 27, 1979
10. Montana-Dakota Utilities Company

1. 79-11211
2. 49-005-24405
3. 103
4. Amoco Production Company
5. Christensen Unit C #1
6. Hartzog Draw
7. Campbell WY
8. 17.0 million cubic feet
9. June 27, 1979
10. Panhandle Eastern Pipeline Company

1. 79-11212
2. 49-005-24797
3. 103
4. Amoco Production Company
5. Christensen D Unit #1
6. Hartzog Draw
7. Campbell WY
8. .1 million cubic feet
9. June 27, 1979
10. Panhandle Eastern Pipe Line Company

1. 79-11213
2. 49-005-24614
3. 103
4. Amoco Production Company
5. Christensen Unit #1
6. Hartzog Draw
7. Campbell WY
8. 20.0 million cubic feet
9. June 27, 1979
10. Panhandle Eastern Pipeline Company

1. 79-11214
2. 49-005-24615
3. 103
4. Amoco Production Company
5. Christensen B #1
6. Hartzog Draw
7. Campbell WY
8. 41.0 million cubic feet
9. June 27, 1979
10. Panhandle Eastern Pipeline Company

1. 79-11215
2. 49-005-24834
3. 103
4. Amoco Production Company
5. Camblin #2
6. Hartzog Draw
7. Campbell WY
8. 16.0 million cubic feet
9. June 27, 1979
10. Phillips Petroleum Company

1. 79-11216
2. 49-005-24818
3. 103
4. Amoco Production Company
5. Camblin #1
6. Hartzog Draw
7. Campbell WY
8. 24.0 million cubic feet
9. June 27, 1979
10. Phillips Petroleum Company

1. 79-11217
2. 49-037-21036
3. 102
4. Amoco Production Company
5. Champlin 536 Amoco A #1
6. Wildcat
7. Sweetwater WY
8. 48.0 million cubic feet
9. June 27, 1979
10. Cities Service Gas Company

1. 79-11218
2. 49-037-20955
3. 102
4. Amoco Production Company
5. Champlin 441 Amoco A #1
6. Wamsutter
7. Sweetwater WY
8. 145.0 million cubic feet
9. June 27, 1979
10. Cities Service Gas Co

1. 79-11219
2. 49-007-20315
3. 102
4. Amoco Production Company
5. Champlin 444 Amoco A #1

6. Unnamed—Wildcat
7. Carbon WY
8. 96.0 million cubic feet
9. June 27, 1979
10. Cities Services Gas Company

1. 79-11220
2. 49-009-21207
3. 103
4. Amoco Production Company
5. Etchemendy A #1
6. Well Draw
7. Converse WY
8. 5.0 million cubic feet
9. June 27, 1979
10. Phillips Petroleum Company

1. 79-11221
2. 49-023-20956
3. 103
4. Amoco Production Company
5. Champlin 451 Amoco A #1
6. Siberia Ridge
7. Sweetwater WY
8. 98.0 million cubic feet
9. June 27, 1979
10. Cities Service Gas Company

1. 79-11222
2. 49-013-20753
3. 103
4. Amoco Production Company
5. Big Sand Draw Gas #16
6. Big Sand Draw
7. Freemont WY
8. 313.0 million cubic feet
9. June 27, 1979
10. Northern Utilities Inc

1. 79-11223
2. 49-007-20379
3. 102
4. Amoco Production Company
5. Champlin 242 D #1
6. Wamsutter
7. Carbon WY
8. 283.0 million cubic feet
9. June 27, 1979
10. Cities Service Gas Co

1. 79-11224
2. 49-037-21037
3. 102
4. Amoco Production Company
5. Champlin 242 Amoco B #1
6. Wildcat
7. Sweetwater WY
8. 222.0 million cubic feet
9. June 27, 1979
10. Cities Service Gas Company

1. 79-11225
2. 49-037-20975
3. 102
4. Amoco Production Company
5. Champlin 450 Amoco A #1
6. Wamsutter
7. Sweetwater WY
8. 81.0 million cubic feet
9. June 27, 1979
10. Cities Service Gas Company

1. 79-11226
2. 49-007-20369
3. 102
4. Amoco Production Company
5. Champlin 226 Amoco B #1
6. Wildcat
7. Carbon WY
8. 206.0 million cubic feet
9. June 27, 1979
10. Cities Service Gas Company

1. 79-11227
2. 49-037-21023
3. 103
4. Kenneth Luff Inc
5. #2-27 Amoco-Champlin
6. Pine Canyon
7. Sweetwater WY
8. 75.0 million cubic feet
9. June 27, 1979
10. Stauffer Chemical Company of Wyoming

1. 79-11228
2. 49-037-21062
3. 103
4. Kenneth Luff Inc
5. #2-17 Amoco-Champlin
6. Crooked Canyon
7. Sweetwater WY
8. 150.0 million cubic feet
9. June 27, 1979
10. Stauffer Chemical Company of Wyoming

1. 79-11229
2. 49-037-21043
3. 103
4. Kenneth Luff Inc
5. #3-9 Amoco-Champlin
6. Crooked Canyon
7. Sweetwater WY—
8. 100.0 million cubic feet
9. June 27, 1979
10. Stauffer Chemical Company of Wyoming

1. 79-11230
2. 49-005-25116
3. 103
4. Continental Oil Company
5. Conoco Wright 29-4
6. House Creek SE 29 T44N R72W
7. Campbell WY
8. 32.8 million cubic feet
9. June 27, 1979
10.

1. 79-11231
2. 49-005-25134
3. 103
4. Continental Oil Company
5. Conoco Wright 32-7
6. House Creek NE 32 T44N R72W
7. Campbell WY
8. 21.9 million cubic feet
9. June 27, 1979
10.

1. 79-11232
2. 49-005-25082
3. 103
4. Continental Oil Co
5. Conoco Wright 33-2
6. House Creek NW 33 T44N B72W
7. Campbell WY
8. 32.8 million cubic feet
9. June 27, 1979
10. Phillips Petr Co

1. 79-11233
2. 49-005-25104
3. 103
4. Continental Oil Co
5. Cosner Ranch 4 Well #6
6. House Creek NW Sec 4 T43N B72W
7. Campbell WY
8. 29.9 million cubic feet
9. June 27, 1979
10. Phillips Petr Co

1. 79-11234
2. 49-005-25043
3. 103
4. Continental Oil Co
5. Cosner Ranch 4 Well #5
6. House Creek NE Sec 4 T43N R72W
7. Campbell WY
8. 23.0 million cubic feet
9. June 27, 1979
10. Phillips Petr Co

1. 79-11235
2. 49-005-25111
3. 103
4. Continental Oil Co
5. Conoco Wright 33-3
6. House Creek SW 33 T44N R72W
7. Campbell WY
8. 27.4 million cubic feet
9. June 27, 1979
10. Phillips Petr Co

1. 79-11236
2. 49-005-25133
3. 103
4. Continental Oil Co
5. Conoco Wright 33 #8
6. House Creek NW NE Sec 33-T44N-R72W
7. Campbell WY
8. 7.3 million cubic feet
9. June 27, 1979
10. Phillips Petr Co

1. 79-11237
2. 49-005-24883
3. 103
4. Continental Oil Co
5. Conoco Wright 33 Well #1
6. House Creek SE Sec 33 T44N R72W
7. Campbell WY
8. 16.4 million cubic feet
9. June 27, 1979
10. Phillips Petroleum Co

1. 79-11238
2. 49-005-25166
3. 103
4. Continental Oil Company
5. Conoco Wright 29-10
6. House Creek SW 29 T44N R72W
7. Campbell WY
8. 5.5 million cubic feet
9. June 27, 1979
10.

1. 79-11239
2. 49-009-00000
3. 103
4. Chaparral Resources Inc
5. Werner #1-19
6. Spearhead Ranch
7. Converse WY
8. 118.6 million cubic feet
9. June 27, 1979
10. Quasar Energy Inc

1. 79-11240
2. 49-041-20171
3. 102
4. Champlin Petroleum Company
5. CPC UPRR 24-11 SESW 11-15N-113W
6. Hank Hollow
7. Uinta WY
8. 140.0 million cubic feet
9. June 27, 1979
10.

1. 79-11241
2. 49-037-00000
3. 103
4. Robert Klabzuba
5. Amoco-Champlin #1-15
6. Ten Mile Draw

7. Sweetwater WY
8. .2 million cubic feet
9. June 27, 1979
10. Stauffer Chemical Co of Wyoming
1. 79-11242
2. 48-035-00000
3. 108
4. John J. Christmann
5. Allen—Wells 1-15
6. Tip Top
7. Sublette WY
8. 400.0 million cubic feet
9. June 27, 1979
10. Northwest Pipeline Corp
1. 79-11243
2. 49-023-00000
3. 103
4. John J. Christmann
5. Red Gap 2-20
6. South Hogsback
7. Lincoln WY
8. 350.0 million cubic feet
9. June 27, 1979
10. Northwest Pipeline Corp
1. 79-11244
2. 49-009-00000
3. 103
4. Petroleum Inc
5. Conoco Mortons Inc #3
6. Mikes Draw (Teapot)
7. Converse, WY
8. 12.0 million cubic feet
9. June 27, 1979
10. Phillips Petroleum Company
1. 79-11245
2. 49-009-00000
3. 103
4. Petroleum Inc
5. Holmes C #1
6. Mikes Draw (Teapot)
7. Converse, WY
8. 20.0 million cubic feet
9. June 27, 1979
10. Phillips Petroleum Company
1. 79-11246
2. 49-013-20763
3. 102
4. Monsanto Company
5. MDU State #1-16
6. Madded
7. Fremont, WY
8. 1825.0 million cubic feet
9. June 27, 1979
10. Colorado Interstate Gas Company
1. 79-11247
2. 49-005-25036
3. 103
4. The Superior Oil Company
5. Lowery 1
6. Kingsbury Creek
7. Campbell, WY
8. 4.0 million cubic feet
9. June 27, 1979
10.
1. 79-11248
2. 49-029-20765
3. 103
4. Resources Investment Corporation
5. McKinley #1
6. Bearcat
7. Park, WY
8. .1 million cubic feet
9. June 27, 1979
10.
1. 79-11249
2. 49-009-00000
3. 103
4. Mitchell Energy Corporation
5. Cities-Johnson #1
6. Mikes Draw
7. Converse, WY
8. 7.2 million cubic feet
9. June 27, 1979
10. Liquid Energy Corporation
1. 79-11250
2. 49-009-00000
3. 103
4. Mitchell Energy Corporation
5. Steinle 4-15
6. Mikes Draw
7. Converse, WY
8. 10.8 million cubic feet
9. June 27, 1979
10. Liquid Energy Corporation
1. 79-11251
2. 49-009-00000
3. 103
4. Mitchell Energy Corporation
5. Mohr 1-11
6. Mikes Draw
7. Converse, WY
8. 16.0 million cubic feet
9. June 27, 1979
10. Liquid Energy Corporation
1. 79-11252
2. 49-009-00000
3. 103
4. Mitchell Energy Corporation
5. Fenderson 2-14
6. Mikes Draw
7. Converse, WY
8. 7.3 million cubic feet
9. June 27, 1979
10. Liquid Energy Corporation
1. 79-11253
2. 49-009-00000
3. 103
4. Mitchell Energy Corporation
5. Fenderson 3-14
6. Mikes Draw
7. Converse, WY
8. 5.8 million cubic feet
9. June 27, 1979
10. Liquid Energy Corporation
1. 79-11254
2. 49-009-00000
3. 103
4. Mitchell Energy Corporation
5. Mohr 3-2
6. Mikes Draw
7. Converse, WY
8. 3.2 million cubic feet
9. June 27, 1979
10. Liquid Energy Corporation
1. 79-11255
2. 49-009-00000
3. 103
4. Mitchell Energy Corporation
5. Mohr 4-2
6. Mikes Draw
7. Converse, WY
8. 7.2 million cubic feet
9. June 27, 1979
10. Liquid Energy Corporation
1. 79-11256
2. 49-025-06243
3. 102
4. Dart Inc
5. Oconner
6. Se Castle Creek
7. Natrona, WY
8. 146.0 million cubic feet
9. June 27, 1979
10. Northern Gas Company
1. 79-11257
2. 49-009-00000
3. 103
4. Mitchell Energy Corporation
5. B B State, 3-16 07-9174
6. Mikes Draw
7. Converse, WY
8. 4169.0 million cubic feet
9. June 27, 1979
10. McCulloch Gas Processing Corporation
1. 79-11258
2. 49-019-20396
3. 102
4. WEBB Resources Inc
5. #12-2 Christensen
6. Table Mountain Field
7. Johnson, WY
8. 30.0 million cubic feet
9. June 27, 1979
10. Phillips Petroleum Company
1. 79-11259
2. 49-019-20397
3. 102
4. WEBB Resources Inc
5. #12-4 Christensen
6. Table Mountain Field
7. Johnson, WY
8. 15.0 million cubic feet
9. June 27, 1979
10. Phillips Petroleum Company
1. 79-11260
2. 49-019-20399
3. 102
4. WEBB Resources Inc
5. #2-9 Christensen
6. Table Mountain Field
7. Johnson, WY
8. 25.0 million cubic feet
9. June 27, 1979
10. Phillips Petroleum Company

U.S. Geological Survey Metairie, LA.

1. Control Number (F.E.R.C./STATE)
2. API Well Number
3. Section of NGPA
4. Operator
5. Well name
6. Field or OCS area name
7. County, State or block no.
8. Estimated annual volume
9. Date received at FERC
10. Purchaser(s)
1. 79-11261
2. 17-709-40341-0000-0
3. 102
4. Gulf Oil Corporation
5. Eugene Island Blk 252 OCS G-0983 #G
6. Eugene Island
7. 252000
8. 2543.0 million cubic feet
9. June 27, 1979
10. Sea Robin Pipeline, Texas Eastern Transmission Corp
1. 79-11262
2. 17-709-40265-0000-0
3. 102
4. Gulf Oil Corporation
5. Eugene Island Blk 238 #3(H-1) OCS G

6. Eugene Island
7. 23800
8. 4920.0 million cubic feet
9. June 27, 1979
10. Sea Robin Pipeline Company, Texas Eastern Transmission Corp
1. 79-11263
2. 17-708-40314-0000-0
3. 102
4. Shell Oil Company
5. B-31
6. South Marsh Island
7. 130000
8. 43.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipe Line Corp
1. 79-11264
2. 17-709-40312-0000-0
3. 102
4. Gulf Oil Corporation
5. Eugene Island Block 238 OCS G 0983
6. Eugene Island Blk 238
7. 252000
8. 1620.0 million cubic feet
9. June 27, 1979
10. Sea Robin Pipeline Co, Texas Eastern Transmission Corp
1. 79-11265
2. 17-709-40291-0000-0
3. 102
4. Gulf Oil Corporation
5. Eugene Island Blk 252 OCS G-0983 #G
6. Eugene Island-
7. 252000
8. 466.0 million cubic feet
9. June 27, 1979
10. Sea Robin Pipeline Co, Texas Eastern Transmission Corp
1. 79-11266
2. 17-711-40428-0000-0
3. 102
4. Ocean Production Company
5. OCS-068 #3A
6. Ship Shoal 113 Field
7. 118000
8. 160.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipeline Corp
1. 79-11267
2. 17-708-40196-0000-0
3. 102
4. Shell Oil Company
5. B-8
6. South Marsh Island
7. 130000
8. 35.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipe Line Corp
1. 79-11268
2. 17-709-40330-0000-0
3. 102
4. Gulf Oil Corporation
5. Eugene Island Block 252 OCS G-0983
6. Eugene Island
7. 252000
8. 10044.0 million cubic feet
9. June 27, 1979
10. Sea Robin Pipeline Company Texas Eastern Transmission Corp.
1. 79-11269
2. 17-704-40365-0100-0
3. 102
4. Transco Exploration Company
5. A-9
6. East Cameron
7. 263000
8. 15000.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipe Line Corp.
1. 79-11270
2. 17-708-40209-0000-0
3. 102
4. Shell Oil Company
5. B-12
6. South Marsh Island
7. 130000
8. 95.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipe Line Corp.
1. 79-11271
2. 17-720-40050-0000-0
3. 102
4. Gulf Oil Corporation
5. OCS G-1101 well F-13 W/D Blk. 117
6. West Delta
7. 117000
8. 200.0 million cubic feet
9. June 27, 1979
10. Texas Eastern Transmission Corp.
1. 79-11272
2. 17-709-40291-0000-0
3. 102
4. Gulf Oil Corporation
5. Eugene Island Blk. 252 OCS G-0983 #G
6. Eugene Island
7. 252000
8. 3402.0 million cubic feet
9. June 27, 1979
10. Sea Robin Pipeline Company Texas Eastern Transmission Corp.
1. 79-11273
2. 17-708-40167-0000-0
3. 102
4. Shell Oil Company
5. B-1
6. South Marsh Island
7. 130000
8. 70.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipeline Corp.
1. 79-11274
2. 17-708-40214-0000-0
3. 102
4. Shell Oil Company
5. B-13
6. South Marsh Island
7. 130000
8. 70.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipe Line Corp.
1. 79-11386
2. 17-724-40109-0000-0
3. 102
4. Chevron USA Inc.
5. OCS-G-2955 #B-1
6. Main Pass
7. 236000
8. 819.0 million cubic feet
9. July 2, 1979
10. Southern Natural Gas Co.
1. 79-11387
2. 17-724-40113-0000-0
3. 102
4. Chevron USA Inc.
5. OCS-G-2955 #B-2
6. Main pass 133
7. 236000
8. 1489.0 million cubic feet
9. July 2, 1979
10. Southern Natural Gas Co.
1. 79-11388
2. 17-710-40733-0000-0
3. 102
4. Texaco Inc.
5. OCS-G-2321 EI 348 No. A-2
6. Eugene Island
7. 348000
8. 730.0 million cubic feet
9. July 2, 1979
10. Texas Gas Transmission Corp. Tennessee Gas Pipeline Co.
1. 79-11389
2. 17-704-40412-0100-0
3. 102
4. Transco Exploration Company
5. A-15
6. East Cameron
7. 263000
8. 15000.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipe Line Corp.
1. 79-11390
2. 17-712-40187-0000-0
3. 102
4. CNG Producing Company
5. B-2-81
6. Ship Shoal
7. 271000
8. 2345.0 million cubic feet
9. June 27, 1979
10. Consolidated Gas Supply Corp. Texas Gas Transmission Corp. Columbia Gas Transmission Corp.
1. 79-11391
2. 17-704-40422-0000-0
3. 102
4. Transco Exploration Company
5. A-12
6. East Cameron
7. 263000
8. 15000.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipe Line Corp.
1. 79-11392
2. 17-704-40425-0000-0
3. 102
4. Transco Exploration Company
5. A-16
6. East Cameron
7. 263000
8. 15000.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipe Line Corp.
1. 79-11393
2. 17-708-40246-0000-0
3. 102
4. Shell Oil Company
5. B-19
6. South Marsh Island
7. 131000
8. 100.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipe Line Corp.
1. 79-11394
2. 17-704-40386-0000-0
3. 102
4. Transco Exploration Company
5. A-7
6. East Cameron
7. 263000
8. 15000.0 million cubic feet
9. June 27, 1979

10. Transcontinental Gas Pipe Line Corp.

1. 79-11395
2. 17-711-40437-0000-0
3. 102
4. Ocean Production Company
5. OCS-063 #35
6. Ship shoal 113 field
7. 93000
8. 275.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipe Line Corp.

1. 79-11396
2. 17-706-40299-0000-0
3. 102
4. Chevron USA Inc.
5. OCS-G-2081 #6
6. Vermilion
7. 262000
8. 200.0 million cubic feet
9. June 27, 1979
10.

1. 79-11397
2. 17-709-40312-0000-0
3. 102
4. Gulf Oil Corporation
5. Eugene Island Blk. 252 OCS G-0983 #G-2
6. Eugene Island
7. 252000
8. 1944.0 million cubic feet
9. June 27, 1979
10. Sea Robin Pipeline Company Texas Eastern Transmission Corp.

1. 79-11398
2. 17-709-40310-0000-0
3. 102
4. Gulf Oil Corporation
5. Eugene Island Blk. 252 OCS G-0983 #G-2
6. Eugene Island
7. 252000
8. 4212.0 million cubic feet
9. June 27, 1979
10. Sea Robin Pipeline Co. Texas Eastern Transmission Corp.

1. 79-11399
2. 17-709-40310-0000-0
3. 102
4. Gulf Oil Corporation
5. Eugene Island Blk 252 OCS G-0983 #G-2
6. Eugene Island
7. 252000
8. 3888.0 million cubic feet
9. June 27, 1979
10. Sea Robin Pipeline Co. Texas Eastern Transmission Corp.

1. 79-11400
2. 17-704-40387-0000-0
3. 102
4. Transco Exploration Company
5. A-11
6. East Cameron
7. 263000
8. 15000.0 million cubic feet
9. June 27, 1979
10. Transcontinental Gas Pipe Line Corp.

U.S. Geological Survey, Albuquerque, N. Mex.

1. Control Number (FERC/State)
2. API Well Number
3. Section of NGPA
4. Operator
5. Well name
6. Field or OCS area name
7. County, State or Block No.
8. Estimated Annual Volume
9. Date Received at FERC
10. Purchaser(s)

1. 79-11302
2. 30-045-22934-0000-0
3. 103
4. Kimbark Operating Co
5. Storey #4
6. Blanco-Pictured Cliff
7. San Juan
8. 182.0 million cubic feet
9. June 28, 1979
10. Southwest Gas Corporation

1. 79-11303
2. 30-045-22935-0000-0
3. 103
4. Kimbark Operating Co
5. Horton #10
6. Blanco-Pictured Cliff
7. San Juan
8. 438.0 million cubic feet
9. June 28, 1979
10. Southwest Gas Corporation

1. 79-11304
2. 30-039-05756-0000-0
3. 108
4. Southland Royalty Co
5. Arizona Jicarilla #4
6. Blanco-Pictured Cliffs
7. Rio Arriba NM
8. 9.0 million cubic feet
9. June 28, 1979
10. Gas Co of New Mexico

1. 79-11305
2. 30-045-06642-0000-0
3. 108
4. Southland Royalty Co
5. Hanks #5
6. Fulcher Kutz Pictured Cliffs
7. San Juan NM
8. 12.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79-11306
2. 30-045-06764-0000-0
3. 108
4. Southland Royalty Co
5. Hanks #10
6. Blanco Pictured Cliffs
7. San Juan NM
8. 8.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79-11307
2. 30-045-07141-0000-0
3. 108
4. Southland Royalty Co
5. Hubbell #2
6. Fulcher Kutz Pictured Cliffs
7. San Juan NM
8. 7.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79-11308
2. 30-045-07160-0000-0
3. 108
4. Southland Royalty Co
5. Hubbell #1
6. Fulcher Kutz Pictured Cliffs
7. San Juan NM
8. 4.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79-11309
2. 30-045-20717-0000-0
3. 108
4. Southland Royalty Co
5. Grenier A #A6
6. Aztec Pictured Cliffs
7. San Juan NM
8. 7.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79-11310
2. 30-045-08779-0000-0
3. 108
4. Southland Royalty Co
5. Grenier B #1
6. Aztec Pictured Cliffs
7. San Juan NM
8. 10.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79-11311
2. 30-045-13240-0000-0
3. 108
4. Southland Royalty Co
5. Reid #3
6. Aztec Pictured Cliffs
7. San Juan NM
8. 19.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79-11312
2. 30-045-20429-0000-0
3. 108
4. Southland Royalty Co
5. Grenier B#9
6. Aztec Pictured Cliffs
7. San Juan NM
8. 3.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79-11313
2. 30-045-13251-0000-0
3. 108
4. Southland Royalty Co
5. McClanahan #3
6. Fulcher Kutz Pictured Cliffs
7. San Juan NM
8. 8.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79-11314
2. 30-045-07356-0000-0
3. 108
4. Southland Royalty Co
5. Reid #20
6. Blanco Mesa Verde
7. San Juan NM
8. 10.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79-11324
2. 30-045-20477-0000-0
3. 108
4. Southland Royalty Co
5. East #13
6. Aztec Pictured Cliffs
7. San Juan NM
8. 2.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79-11325
2. 30-045-20488-0000-0
3. 108
4. Southland Royalty Co

5. East #14
6. Aztec Pictured Cliffs
7. San Juan NM
8. 8.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11326
2. 30–045–07513–0000–0
3. 108
4. Southland Royalty Co
5. McClanahan #18
6. Blanco Mesa Verde
7. San Juan NM
8. 13.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11327
2. 30–039–05785–0000–0
3. 108
4. Southland Royalty Co
5. Arizona Jicarilla #5
6. Blanco Pictured Cliffs
7. Rio Arriba NM
8. 10.0 million cubic feet
9. June 28, 1979
10. Gas Co of New Mexico

1. 79–11328
2. 30–039–05862–0000–0
3. 108
4. Southland Royalty Co
5. Arizona Jicarilla #8
6. Blanco Pictured Cliffs
7. Rio Arriba Nm
8. 3.0 million cubic feet
9. June 28, 1979
10. Gas Co of New Mexico

1. 79–11329
2. 30–039–21037–0000–0
3. 108
4. Southland Royalty Co
5. Arizona Jicarilla #B–7
6. Blanco Pictured Cliffs
7. Rio Arriba NM
8. 6.0 million cubic feet
9. June 28, 1979
10. Gas Company of New Mexico

1. 79–11330
2. 30–045–20555–0000–0
3. 108
4. Southland Royalty Co.
5. East #20
6. Aztec Pictured Cliffs
Juan NM
million cubic feet
28, 1979
10. Southern Union Gathering Co

1. 79–11331
2. 30–045–20648–0000–0
3. 108
4. Southland Royalty Co
5. Davis #14
6. Aztec Pictured Cliffs
7. San Juan NM
8. 6.0 million cubic feet
June 28, 1979
Southern Union Gathering Co

79–11332
2. 30–045–20653–0000–0
3. 108
4. Southland Royalty Co
5. Davis #15
6. Aztec Pictured Cliffs
7. San Juan NM
8. 13.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11333
2. 30–045–09015–0000–0
3. 108
4. Southland Royalty Co
5. Grenier A#A2
6. Aztec Pictured Cliffs
7. San Juan NM
8. 10.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11334
2. 30–045–00000–0000–0
3. 108
4. Southland Royalty Co
5. Grenier #9
6. Aztec Pictured Cliffs
7. San Juan NM
8. 5.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11335
2. 30–045–20427–0000–0
3. 108
4. Southland Royalty Co
5. Grenier #18
6. Aztec Pictured Cliffs
7. San Juan NM
8. 10.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co.

1. 79–11336
2. 30–045–20718–0000–0
3. 108
4. Southland Royalty Co
5. East #21
6. Aztec Pictured Cliffs
7. San Juan NM
8. 10.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11337
2. 30–045–08238–0000–0
3. 108
4. Southland Royalty Co
5. Cozzens #1
6. Fulcher Kutz Pictured Cliffs
7. San Juan NM
8. 10.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11338
2. 30–045–08115–0000–0
3. 108
4. Southland Royalty Co
5. Cozzens #2
6. Fulcher Kutz Pictured Cliffs
7. San Juan NM
8. 6.0 million cubic feet
9. June 28, 1979.
10. Southern Union Gathering Co

1. 79–11339
2. 30–045–00000–0000–0
3. 108
4. Southland Royalty Co
5. Cozzens #3
6. Fulcher Kutz Pictured Cliffs
7. San Juan NM
8. 9.0 million cubic feet
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11340
2. 30–045–08450–0000–0
3. 108
4. Southland Royalty Co
5. Hare #5
6. Aztec Pictured Cliffs
7. San Juan, NM
8. 12.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11341
2. 30–045–07631–0000–0
3. 108
4. Southland Royalty Co
5. Cain #4
6. Aztec Pictured Cliffs
7. San Juan, NM
8. 10.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11342
2. 30–045–07209–0000–0
3. 108
4. Southland Royalty Co
5. Lackey Hubbell #2
6. Fulcher Kutz Pictured Cliffs
7. San Juan, NM
8. 7.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering

1. 79–11343
2. 30–045–06028–0000–0
3. 108
4. Southland Royalty Co
5. Hanks 3
6. Fulcher Kutz PC
7. San Juan, NM
8. 17.0 million cubic ft
9. June 28, 1979.
10. Southern Union Gathering Co

1. 79–11344
2. 30–045–07358–0000–0
3. 108
4. Southland Royalty Co
5. Hughes #1
6. Fulcher Kutz Pictured Cliffs
7. San Juan, NM
8. 7.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11345
2. 30–045–06289–0000–0
3. 108
4. Southland Royalty Co
5. Hudson A D #2
6. Fulcher Kutz Pictured Cliffs
7. San Juan, NM
8. 7.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11346
2. 30–045–07536–0000–0
3. 108
4. Southland Royalty Co
5. Reid #11
6. Aztec Pictured Cliffs
7. San Juan, NM
8. 6.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11347
2. 30–045–07788–0000–0
3. 108
4. Southland Royalty Co
5. Hare #4
6. Aztec Pictured Cliffs

7. San Juan, NM
8. 18.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11348
2. 30–045–09020–0000–0
3. 108
4. El Paso Natural Gas Company
5. Wood 2
6. Aztec-Pictured Cliffs Gas
7. San Juan, NM
8. 21.2 million cubic ft
9. June 28, 1979
10. El Paso Natural Gas Company

1. 79–11349
2. 30–039–05092–0000–0
3. 108
4. Sherman F Wagenseller
5. Mobil Apache #5
6. South Blanco PC
7. Rio Arriba, NM
8. 1.3 million cubic ft
9. June 28, 1979
10. El Paso Gas Co

1. 79–11350
2. 30–039–05063–0000–0
3. 108
4. Lionel R Levinson
5. Pubco Apache #3
6. South Blanco PC
7. Rio Arriba, NM
8. 6.0 million cubic ft
9. June 28, 1979
10. El Paso Gas Company

1. 79–11351
2. 30–045–22933–0000–0
3. 103
4. Kimbark Operating Co
5. Horton #5
6. Blanco-Pictured Cliff
7. San Juan, NM
8. 401.0 million cubic ft
9. June 28, 1979
10. Southwest Gas Corporation

1. 79–11352
2. 30–039–05085–0000–0
3. 108
4. Trans Delta Oil & Gas Co Inc
5. Jicarilla J–2
6. South Blanco
7. Rio Arriba, NM
8. 8.0 million cubic ft
9. June 28, 1979
10. El Paso Natural Gas Company

1. 79–11353
2. 30–039–05094–0000–0
3. 108
4. Trans Delta Oil & Gas Co Inc
5. Jicarilla J–3
6. South Blanco
7. Rio Arriba, NM
8. 9.4 million cubic ft
9. June 28, 1979
10. El Paso Natural Gas Company.

1. 79–11354
2. 30–039–05117–0000–0
3. 108
4. Trans Delta Oil & Gas Co Inc
5. Elliott Federal 2
6. South Blanco
7. Rio Arriba, NM
8. 9.7 million cubic ft
9. June 28, 1979
10. El Paso Natural Gas Company

1. 79–11355
2. 30–045–07570–0000–0
3. 108
4. Southland Royalty Co
5. Reid #14
6. Aztec Pictured Cliffs
7. San Juan, NM
8. 10.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11356
2. 30–045–06817–0000–0
3. 108
4. Southland Royalty Co
5. Hanks #4
6. Fulcher Kutz Pictured Cliffs
7. San Juan, NM
8. 16.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11357
2. 30–045–06878–0000–0
3. 108
4. Southland Royalty Co
5. Hanks #2
6. Fulcher Kutz Pictured Cliffs
7. San Juan, NM
8. 11.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering CO

1. 79–11358
2. 30–045–20458–0000–0
3. 108
4. Southland Royalty Co
5. Hare #21
6. Aztec Pictured Cliffs
7. San Juan, NM
8. 11.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11359
2. 30–045–08655–0000–0
3. 108
4. Southland Royalty Co
5. Hare #13
6. Aztec Pictured Cliffs
7. San Juan, NM
8. 12.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11360
2. 30–045–07436–0000–0
3. 108
4. Southland Royalty Co
5. McClanahan #12
6. Aztec Pictured Cliffs
7. San Juan, NM
8. 18.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11361
2. 30–045–07639–0000–0
3. 108
4. Southland Royalty Co
5. Cain #7
6. Aztec Pictured Cliffs
7. San Juan, NM
8. 18.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11362
2. 30–045–20499–0000–0
3. 108
4. Southland Royalty Co
5. Grenier #20
6. Blanco Pictured Cliffs
7. San Juan, NM
8. 6.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11363
2. 30–045–07312–0000–0
3. 108
4. Southland Royalty Co
5. Newman A #A–6
6. Fulcher Kutz Pictured Cliffs
7. San Juan, NM
8. 12.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11364
2. 30–045–08035–0000–0
3. 108
4. Southland Royalty Co
5. Cozzens #4
6. Fulcher Kutz Pictured Cliffs
7. San Juan, NM
8. 2.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11365
2. 30–045–08017–0000–0
3. 108
4. Southland Royalty Co
5. Cozzens #5
6. Fulcher Kutz Pictured Cliffs
7. San Juan, NM
8. 6.0 million cubic ft
9. June 28, 1979
10. Southern Union Gathering Co

1. 79–11366
2. 30–039–05678–0000–0
3. 108
4. Brooks Hall Oil Corp
5. Jicarilla 10 #1
6. Basin-Dakota
7. Rio Arriba, NM
8. 9.3 million cubic ft
9. June 28, 1979
10. El Paso Natural Gas Company

U.S. Geological Survey, Casper, Wyo.

1. Control Number (FERC/State)
2. API Well Number
3. Section of NGPA
4. Operator
5. Well Name
6. Field or OCS Area Name
7. County, State or Block No.
8. Estimated Annual Volume
9. Date received at FERC
10. Purchaser(s)

1. 79–11140
2. 30–047–30424–0000–0
3. 103
4. Gas Producing Enterprises Inc
5. Natural Buttes 11–14–9–20
6. Bitter Creek
7. Uintah, UT
8. 82.0 million cubic ft
9. June 21, 1979
10. Colorado Interstate Gas Co

The applications for determination in these proceedings together with a copy or description of other materials in the record on which such determinations were made are available for inspection, except to the extent such material is treated as confidential under 18 CFR 275.206, at the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Persons objecting to any of these final determinations may, in accordance with 18 CFR 275.203 and 18 CFR 275.204, file a protest with the Commission within fifteen (15) days of the date of publication of this notice in the Federal Register.

Please reference the FERC Control Number in all correspondence related to these determinations.

Kenneth F. Plumb

Secretary

[FR Doc 79-22643 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

Office of Hearings and Appeals

Implementation of Special Refund Procedures; Issuance of Final Decision and Order

Under the procedural regulations of the Department of Energy, the Special Counsel for Compliance may request the Office of Hearings and Appeals to formulate and implement a process "pursuant to which refunds may be made to injured persons in order to remedy the effects of a violation" of the DOE Regulations. 10 CFR 205.280. We are now providing notice to the public that the Office of Hearings and Appeals has issued a final Decision and Order that establishes the procedures it will use in distributing approximately $42,240,000 to qualified persons. The full text of the Decision and Order follows this Notice.

The $42.24 million is to be tendered to the Department by the Gulf Oil Corporation within 15 days after a consent order entered into by Gulf and the DOE Office of Special Counsel on July 26, 1978, is made final. (43 FR 34185, August 3, 1978). (Consent Order published for public comment). Under the terms of the Decision and Order, a priority class will receive the first distribution from the Gulf refund amount. This class includes all direct purchasers of petroleum products from Gulf during the relevant period and all motorists that purchased gasoline from any Gulf retail outlet for their own personal use during the relevant period. Also in the priority class are all homeowners that purchased heating oil from Gulf during the relevant period for use in their homes. The maximum amount of the refund to which a qualified person will be entitled is derived by multiplying the number of gallons of petroleum products the business entity or individual purchased from Gulf by $.00122.

The procedures also permit requests for refunds to be submitted on a class basis. Those applications will be evaluated by the Office of Hearings and Appeals and a separate decision will be issued.

The procedures contained in the following Decision reflect our full consideration of the comments that members of the public submitted in response to previous proposals of the Office of Hearings and Appeals for distributing the refund amount. (44 FR 16475, March 19, 1979; 43 38548, August 28, 1979; Transcript of Public Hearing (September 26, 1978).

The next step in the implementation of the Gulf refund procedures will be the issuance of an Order by the Office of Hearings and Appeals indicating how the $42.24 million refund amount will be held pending a determination of individual claims for refunds. That Order will be issued to Gulf and will relate to custody of the funds and the interest that the funds will earn. The following step in the refund process will be an invitation to members of the public to submit individual claims for refunds. That invitation will appear in the Federal Register, in a press release the Department will issue, and possibly in advertisements placed in appropriate publications. The announcement will describe the information that members of the public should submit in an application for refund and will specify the deadline for the submission of all claims. If possible, a form will also be made available for this purpose.

We are, in addition, exploring the possibility of arranging for direct payment to be made to purchasers of Gulf products without the necessity of a formal application. This procedure, if technically feasible, will apply to those business entities that bought petroleum products directly from Gulf during the relevant time period and actually used the products involved rather than reselling it. It will also, if technically feasible, apply to motorists and homeowners who bought products from Gulf during the relevant period with credit cards.

We will very shortly announce the specific procedures that will be used in processing individual claims for refunds. In order to avoid duplication, individual claims should not be submitted until that announcement is made.

Dated: July 17, 1979.

Melvin Goldstein,

Director, Office of Hearings and Appeals.

Department of Energy,

Washington, D.C. 20461.

July 13, 1979.

Decision and Order of the Department of Energy

Special Refund Procedures

Name of Petitioner: Office of Special Counsel for Compliance, Department of Energy.

Date of Filing: March 2, 1979.

Case Number: DFF-0001.

This proceeding establishes special procedures that the Department of Energy will use in refunding to customers of the Gulf Oil Corporation approximately $42,240,000. On August 22, 1978, the Office of Hearings and Appeals issued a Decision and Order in response to a Petition for Special Redress filed by the Office of Special Counsel. The Decision described in considerable detail the refund procedures that the Office of Hearings and Appeals intended to implement on an interim basis pending receipt of written comments and oral presentations. *Office of Special Counsel for Compliance*, 1 DOE Par. 82,586 (1978); 43 FR 38,548 (1978). A public hearing was held on September 26, 1978, and written comments were filed by 34 individuals and firms.

On February 9, 1979, the Department of Energy adopted new procedural regulations for the distribution of refunds. Notice of Rulemaking, 44 FR 8561 (1979). Those regulations, which are contained in Subpart V of the DOE procedural regulations (10 CFR Part 205), establish special refund procedures which can be activated by the Office of Hearings and Appeals upon petition by the Office of Special Counsel or by the Office of Enforcement. In view of the adoption of those special refund regulations, the Office of Special Counsel withdrew the Petition for Special Redress that it had filed and instead requested that the Special Refund Procedures set forth in Subpart V be activated with respect to the Gulf Consent Order. *See* 10 CFR 205.281. On March 13, 1979, a Proposed Decision and Order was issued in the refund proceeding. The March 13 proposal contained revised procedures for distributing the Gulf refund. 2 CCH Fed. Energy Guidelines Par. 17,143 (1979). Public comment was requested on the proposed procedures. *Id.*; 44 FR 16,475 (March 19, 1979).

After considering the new Petition and the comments submitted both in the original special redress proceeding and in this special refund proceeding, we have concluded that a revised determination should be issued with regard to the Petition of the Special Counsel. This revised determination incorporates a number of the changes recommended by individuals who submitted comments in each of the proceedings.

I. Background

In its March 2 Petition for the Implementation of Special Refund Procedures, the Special Counsel for Compliance of the Department of Energy

(OSC) requested the Office of Hearings and Appeals to adopt and implement procedures in order to distribute overcharges to purchasers of products sold by the Gulf Oil Company. According to the Petition, these refunds are being paid by Gulf pursuant to a Consent Order entered into by Gulf and the OSC on July 26, 1978. 43 FR 34,185 (1978); *see* 10 CFR 205.281. The Special Counsel stated that he was not able to identify at that time the particular purchasers of Gulf products who would be entitled to refunds.

In the Consent Order, the OSC and Gulf reached an agreement to settle a compliance proceeding that had been instituted against Gulf in April 1977 by the issuance of a Notice of Proposed Disallowance (NOPD). The Federal Energy Administration alleged in the NOPD that Gulf had overstated its costs with respect to interaffiliate imported crude oil transactions by $79.6 million for the period October 1973 through May 1975. The DOE subsequently reduced the amount of disallowance by $5.7 million on the basis of corrections to information that had been reported to the DOE and adjustments to maximum and representative prices for crude oil that had been transferred by Gulf. In the Consent Order the OSC and Gulf agreed to settle the disallowance claim and also any overrecoveries that Gulf had made in connection with its purchases of Indonesian Katapa crude oil through a foreign affiliate during the period between August 1973 and January 1976. The Consent Order also referred to overrecoveries alleged in a Notice of Probable Violation issued to Gulf on May 8, 1974.

Under the terms of the Consent Order, Gulf agreed to tender $42,240,000 to the United States in lieu of any further remedial action with respect to these matters. However, the Consent Order states that:

Gulf and DOE recognize that the time periods involved and the determination of proper costs allowable make it most difficult to determine whether any person sustained an overcharge in the purchase of covered products from Gulf * * *

In view of the difficulties that were perceived in reaching a determination as to whether any particular person was overcharged as a result of the alleged Gulf actions referred to in the Consent Order, the DOE agreed to accept responsibility for establishing an administrative procedure for evaluating claims for a portion of the refund and making restitution to persons presenting valid claims. In the present Petition, the OSC requests that special procedures be established by the Office of Hearings and Appeals under Part 205, Subpart V for the distribution of refunds to affected persons.

II. Authority

Section 205.280 of the DOE procedural regulations provides that special refund procedures may be adopted by the Office of Hearings and Appeals upon petition by a DOE enforcement official when that official is unable to readily identify persons who are entitled to refunds specified in a remedial order or a consent order. After considering the Petition filed by the OSC and the record in this proceeding, we have determined that special procedures should be implemented in order to compensate injured customers in this proceeding. Gulf is a major integrated petroleum firm engaged in the production, transportation, refining and marketing of crude oil and an extensive schedule of petroleum products. It is one of the largest petroleum firms in the United States, and the purchasers of its products number in the millions. Because of the nature of the particular pricing practices alleged in the NOPD, which concern a fundamental element in a refiner's calculation of maximum permissible prices, each purchaser of Gulf products marketed throughout the United States was potentially affected. These factors and the flexibility accorded refiners under the refiner price rule of the Mandatory Petroleum Regulations make it extremely difficult to allocate specific overcharges to any particular sales transaction or to identify specific customers who were overcharged. That determination is further complicated in this case by the fact that the practices in question occurred as long ago as five years.

In other words, even though overcharges may have occurred, the discretion that Gulf possessed in determining its prices makes it very unlikely that any individual claimant could prove the nature and extent of a direct injury. Therefore, unless special procedures are adopted, there would appear to be little likelihood that individual purchasers and consumers would be able to obtain refunds. This situation would occur despite the fact that it is likely that purchasers and consumers as a class are entitled to refunds based on the Consent Order. Under these circumstances it is necessary to implement special procedures to ensure that the persons who would be affected by Gulf's alleged transfer price mechanism will benefit from the terms of the Consent Order.

We have therefore concluded that special claims procedures are necessary and appropriate in this case. The specific procedures that will be implemented in this proceeding for distributing refunds are set forth in the Appendix. They will be explained in detail below.

III. Notice to Purchasers; Administration of Claims

The type of regulatory violations referred to in the Consent Order could have had an effect during the relevant time period upon every purchaser of crude oil from Gulf under the Buy-Sell Program (10 CFR 211.65) and upon every purchaser of refined products or residual fuel oil from Gulf. Consequently, there are special problems associated with the establishment of a procedure for adjudicating claims and distributing refunds.

The large number of potential claimants first presents the question of the form of notice that should be given to individuals who wish to request a refund. We believe that notice should include publication in the Federal Register and the preparation of appropriate press releases that will specify the exact time period during which applications for refunds will be received. The procedures described in the Appendix to this Decision specifically provide for those types of notice. In addition, individual purchasers of Gulf products will, to the extent practicable, be directly notified of the procedures avaiable for filing claims. We understand that many of the direct purchasers of covered products from Gulf and Gulf credit card purchasers during the period in question can be identified through records maintained by Gulf. We intend to request the assistance of Gulf, consistent with the terms of the Consent Order, in connection with notification efforts. Where necessary, direct mail notices will also be sent to various trade and consumer organizations, who may then notify their members. We are also considering supplementing the types of notice already discussed by advertising in newspapers and periodicals of general circulation and publishing announcements in trade and consumer publications. Funds will be appropriated for the purpose of providing notice to customers from the refund to be remitted by Gulf.

In addition, Gulf has expressed a willingness to assist the DOE, consistent with the terms of the Consent Order, in the evaluation of refund claims. Its assistance will be useful in verifying information submitted by claimants and in providing additional information or documents within its control to the DOE or individual claimants. It may, in fact, be possible to make refunds directly to some classes of customers by utilizing purchase records maintained by Gulf. This procedure will eliminate the requirement that each purchaser file a formal refund application. We intend to explore this possibility further when the Consent Order is issued in final form.

We contemplate that Gulf will provide assistance on a voluntary basis, and consequently claimants should seek necessary factual material by applying directly to Gulf. The Office of Hearings and Appeals will consider the use of compulsory procedures for obtaining information only if voluntary methods for obtaining the information have been unsuccessful. In any case, prior to the issuance of compulsory process Gulf will be afforded an opportunity to present its views regarding the burden that it will experience in complying with individual requests for additional information.

A more fundamental question presented by the large number of potential claimants in this case concerns the processing of individual claims. It would not be feasible as a practical matter for the Office of Hearings and Appeals itself to deal individually with thousands of claims, many of which could be for relatively small amounts. On the other hand, we will not adopt any procedure that effectively prevents small firms or ultimate consumers from presenting legitimate claims for refunds. Consequently, the appended procedures provide that claims may be directed to an administrator who is appointed and supervised by the Office of Hearings and Appeals. The administrator would reach a determination as to those claims under the guidance and supervision of the Office of Hearings and Appeals.

In the Interim Decision issued in the previous special redress proceeding, a *de* *minimis* rule was proposed; we agree, however, with the objection made by some of the commenters that such a provision might unnecessarily bar many justifiable small claims. Since many small purchasers may be identified by Gulf, thus eliminating the need to process individually applications for a great number of small claims, there would not appear to be an appropriate basis for imposing minimum claim requirements. Accordingly, no minimum claims requirement will be imposed at the outset. Instead, the Office of Hearings and Appeals will evaluate the need for a *de minimis* rule after it begins receiving refund claims. A *de minimis* rule will be instituted at that time only to the extent that the amount of a claim does not appear to justify consideration in view of the actual direct costs of evaluating and paying the claim.

IV. Standards for Evaluation

A. *Qualification for Refund.* Any claim for a refund should logically consist, at a minimum, of proof that the claimant purchased during the period covered by the Consent Order Gulf petroleum products that were subject to FEA price regulations. A consumer will generally be able to establish a claim by making that minimum showing.

Because of the nature of their business activities, however, petroleum refiners and resellers will have to make a more substantial showing to establish that they are entitled to a refund. Refiners and resellers might well have had an obligation under the FEA and DOE regulatory program to pass through to their own customers the entire benefit of a decrease in the cost of Gulf products that they sold or refined. The maximum price that a reseller may charge for a covered product is dependent on the cost that it incurs in purchasing that product from its supplier. Similarly, a major component of the maximum prices that a refiner is permitted to charge is the cost of the crude oil that it refines. If a refiner or reseller was already selling a product at its maximum permissible selling price and then received a price reduction from its supplier, the firm would be obligated to pass that reduction on to its own customers on a dollar-for-dollar basis. Therefore, a refiner or reseller in that position would not have been able to benefit from lower prices of Gulf products, and it should not be eligible to receive a refund.

Consequently, in order to qualify for a refund, a refiner or reseller will be required to demonstrate that during the period covered by the Consent Order it could have kept its prices at the same level if it had experienced a cost reduction equal to the amount of the refund claimed. In order to show this a firm must demonstrate that at the time it purchased covered products from Gulf it had unrecovered product costs at least equal to the amount of the refund claim. In addition, it must have maintained a "bank" of unrecovered costs during each month thereafter in order to demonstrate that it did not subsequently recover these costs by increasing its prices. The amount of the refund will be limited to the amount of unrecovered costs available to the claimant for recovery through price increases. A refiner or reseller that has failed to maintain the records necessary to establish that it did not pass through its increased costs will not be eligible to receive a refund. The DOE will require refiners and resellers that do receive a refund to reduce their banks of unrecovered product costs for the product or products concerned. In cases where reports were filed with the FEA, they will also be required to submit amended reports that reflect the reduction in their banks. The compilation by the claimant of the necessary cost information should not be unduly burdensome, since under FEA regulations petroleum firms were required to maintain records of this general type. *See* 10 CFR 210.92. In addition, we intend to scrutinize claims for large refunds carefully on a case-by-case basis. In some of these cases, further evidence may be required of claimants to demonstrate that industry custom, contractual obligations or unusual market factors would not have prevented the firm from retaining the benefits of a cost reduction by Gulf.

A similar showing will not be required in the case of firms in regulated industries. It was originally proposed that public utilities, airlines and other firms whose prices are regulated by various governmental bodies should be required to make the same sort of factual showing required of petroleum resellers and refiners, that is, that they did not pass through to their customers their increased costs of petroleum products purchased from Gulf. However, because of the large number of agencies potentially involved and the complex nature of many of the relevant regulatory programs, we have concluded that the processing of claims will proceed more efficiently if this issue is handled by the regulatory agencies concerned. Consequently, wholesale consumers of Gulf products that are regulated by government agencies will be required to notify the particular agency or agencies concerned of their receipt of a refund from Gulf. The regulatory agencies will then be able to determine what action, if any, should be taken to ensure that the benefits of the refund reach ultimate consumers.

B. *Determination of Refund Amount.* As stated above, the purpose of the refund procedure is to distribute refunds to Gulf customers only to the extent that each particular claimant would have benefited if Gulf had followed a transfer pricing practice different from the practice it in fact adopted in the period specified in the Consent Order. Nevertheless, some approximations will be necessary in determining the amount of the refund in each case. Because of the nature of a crude oil cost disallowance it is exceedingly difficult to establish with precision the exact amount by which a particular firm or person might have been overcharged. Presumptions will therefore be necessary to determine the amount of refunds that should be paid to a particular reseller or consumer.

In fact, overcharges made in this case to particular claimants would be virtually impossible to establish. The allegations upon which the Consent Order is based do not directly concern a pricing violation, but instead involve crude oil costs that the DOE alleged Gulf improperly utilized in calculating its maximum permissible prices for refined petroleum products and for crude oil sold pursuant to the Mandatory Crude Oil Allocation Program.[1] In general, the price rule applicable to refiners provided that a refiner could not charge a price for an item that exceed the weighted average price at which the item was lawfully priced in transactions with the class of purchaser concerned on May 15, 1973, "plus increased product costs incurred between the month of measurement and the month of May 1973 and measured pursuant to the provisions of § 212.83." 10 CFR 212.82(b)(1) (1974).[2] Increased product costs, such as increased transfer costs of crude oil, were placed in a pool of costs which could then be utilized by the refiner in the manner specified in § 212.83. Section 212.83 in general required an equal allocation of those costs to several broad product categories and among classes of purchasers for each product within a category. Each refiner, however, was given considerable discretion with regard to the manner in which it distributed increased costs among products within a single category, and was also permitted in some instances to transfer costs from one category to another. Furthermore, a refiner was not required to recover all increased product costs in the first period in which they were available for recovery under § 212.83, but could instead "bank" some of those costs for recovery in subsequent periods. A refiner was thus permitted to exercise a considerable amount of discretion in deciding when and on which products to pass through costs. The discretion given refiners under the refiner price rule thus makes it extremely difficult to determine with any degree of certainty the maximum price that would have been established for a Gulf product if the firm had not recognized allegedly improper imported oil costs.

A further problem in determining the precise amount of an overcharge to a particular purchaser of Gulf products arises because many purchasers did not buy those products directly from Gulf, but bought them instead from independent resellers. As discussed above, a reseller may have been required to pass through cost reductions to its customers under the reseller price provisions of the Mandatory Petroleum Price Regulations, or it may have been required to pass through a portion of the reduction. Furthermore, regardless of the requirements of the regulations, a reseller may have voluntarily chosen to pass through all or part of any reduction in its product costs, either to meet the prices charged by competitors, or pursuant to contractual provisions, or simply as a customary practice.

However, while it is unquestionably difficult to determine the exact amount by which any particular purchaser may have been overcharged, it is nevertheless likely that if the allegations made by the DOE in the NOPD were correct, purchasers of Gulf products, as a class, paid higher prices than they should have paid and are therefore entitled to refunds. Certain presumptions will therefore be made regarding the manner in which imported crude oil costs were passed through by Gulf and the extent to which customers would have incurred an injury as a result of Gulf's alleged actions.

First, we have presumed that Gulf allocated the entire refund amount to all covered products, including the crude oil, that it sold during the August 19, 1973 through January 31, 1976 period. We have also presumed that these crude oil costs were apportioned equally on a volumetric basis to all covered petroleum products, including crude oil, that Gulf sold during that period. The refund will be apportioned in a similar manner. The data submitted by Gulf indicate that the total volume of covered petroleum products including crude oil sold during the period was 34,505,212,140 gallons. Consequently, the total amount of the refund will be $0.00122 per gallon ($42,240,000 ÷ 34,505,212,140 gallons).[3]

The further presumption has been made that every purchaser of covered products, including crude oil, from Gulf during the period covered by the Consent Order is entitled to the full per gallon refund amount. Essentially this will mean that a governmental entity, a private individual and any other consumer or reseller of a Gulf product may apply for a full refund for the total amount of products that it purchased during the relevant period. All purchasers of Gulf products during the period August 19, 1973 through January 31, 1976 may file applications for refunds during the period to be specified by a subsequent notice in the Federal Register.

In order to accommodate the claims of persons and firms that purchased petroleum products directly from Gulf as well as those that purchased Gulf products through resellers or refiners,f we have concluded that a bifurcated proceeding will be necessary. Under this procedure, the claims of direct purchasers will be considered in the initial stage of the refund proceeding. Under the standards already discussed, direct purchasers from Gulf who consumed the products they purchased will be entitled to receive the full refund amount based solely on quantity of product purchased. Motorists that bought gasoline at service stations owned by Gulf as well as homeowners that bought heating oil directly from facilities owned by Gulf fall into this category. On the other hand, refiners and resellers that purchased petroleum products from Gulf will be entitled to the full refund amount only if they can establish through the existence of banks of unrecovered costs that they would not have been required under the FEA and DOE regulations to reduce their own prices if the refund they are now claiming had instead been reflected in lower product costs. Resellers and refiners must therefore be prepared to show that they had banks for each regulated product during the final month of the overcharge period, January 1976, equal to the amount of the refund claimed. In addition, they must also show that the banks that existed at that time were not later used to support price increases.

In addition to direct purchasers of petroleum products from Gulf, motorists who bought Gulf motor gasoline for personal use in their own automobiles and homeowners who purchased Gulf heating oil for use in their own residences will be included in the first stage of the refund proceeding. As a practical matter, individual motorists and homeowners do not generally know whether the Gulf products that they purchased were sold to them by a Gulf employee or by an independent reseller of Gulf products. It would be anomalous if consumers purchasing the same product from the same type of outlet under the same circumstances were treated differently under the refund procedures. In addition, individual consumers should not be required to make a difficult determination as to the legal status of the firm that sold them petroleum products. An effort to distinguish between ultimate consumers of gasoline and heating oil on the basis of whether the firm that sold the product was operated by Gulf employees or independent businessmen would also present the DOE with difficult problems in administering the refund procedures. Moreover, Gulf itself would also have difficulty distinguishing between direct and indirect purchasers on the basis of the historical records for the 1973 through January 1976 period that are still available. We have therefore concluded that all ultimate consumers that purchased motor gasoline for personal use in automobiles or heating oil for use in the purchaser's residence should be regarded as direct purchasers.

The second stage of the refund proceeding will be devoted to processing claims of all other secondary purchasers of Gulf products. The firms that fall into this category are generally resellers that purchased Gulf products from a direct purchaser. Consumers that are not considered as direct purchasers and that purchased products from a reseller also fall into this category. The funds available to satisfy claims of this type will consist of the revenues that remain after all direct claims have been processed and paid. Since a direct purchaser from Gulf that refined or resold the the product it obtained must satisfy the standards discussed above, it is likely that a substantial portion of the total refund will be available for distribution to secondary purchasers. At either stage of the proceeding if insufficient funds are available to satisfy all approved claims in full, a pro rata reduction of the claims will be made.[4] Thus, if it is necessary to pay less than the full amount of the approved claims of direct purchasers, the claims of indirect or secondary purchasers will not be processed.

It is, of course, true that the presumptions upon which these procedures are based will only approximate actual behavior. For the reasons discussed above, however, conclusive findings cannot be made as to the precise amount a particular purchaser may have been overcharged. It is simply not possible to ascertain the precise manner in which Gulf would have determined the prices of its products to a particular purchaser over a two-and-a-half-year period if it had in fact calculated its imported crude oil costs in a different manner. In our view the presumptions that we have utilized represent the most appropriate method of disbursing the refund by Gulf.

V. Exclusiveness of This Administrative Remedy

Under the terms of the Consent Order. Gulf will be deemed to have determined its crude oil costs in accordance with the applicable regulations after it has paid the refund and complied with the other terms and conditions of the Consent Order. Therefore, the procedures set forth in the Appendix to this Decision will be the only administrative remedy available to persons injured as a result of the alleged violations by Gulf of the transfer pricing regulations. No further DOE compliance proceeding will be instituted against Gulf with regard to these matters.

The Department intends this claims procedure to be the forum through which Gulf customers may obtain refunds with respect to the matters referred to in the Consent Order. However, a person who has been injured as a result of an overcharge may of course file a civil action against Gulf in federal court under Section 210 of the Economic Stabilization Act of 1970 (ESA), Pub. L. 92-210. In order to avoid subjecting Gulf to potential double liability from persons that seek to pursue their available legal remedies under Section 210 of the ESA, we have concluded that the administrative refund proceeding should encompass final judgments obtained during a period of 15 months from the date of publication of this final decision in the Federal Register. Thus, parties that obtain judgments[5] against Gulf during that period can submit that judgment, with the approval of the Special Counsel, in the refund proceeding in order to establish its claim. If the party does not do so, Gulf itself may submit an application based on the judgment on the party's behalf. The claimant will then be entitled to receive from the fund a proportion of the judgment equal to the proportion that the total refund amount, $42.24 million, bears to the total overstatement of landed costs of Gulf's crude oil upon which the judgment was based.

In addition, at the conclusion of the first stage of the refund proceeding, but before any refunds are made, an amount will be designated as a reserve to satisfy any judgments in legal actions commenced against Gulf under Section 210 of the ESA within 15 months from the date of publication of this final decision in the Federal Register. The amount of the reserve fund will be determined by agreement of Gulf and the Office of Special Counsel based upon a reasonable estimate of the amounts that might be necessary to satisfy each such pending judicial proceeding.

The time period for filing all applications will be established by a subsequent Order published in the Federal Register. No applications for refunds will be considered unless they are filed during the specified time period. Those customers of Gulf that are provided with notice by direct mail will have at least 90 days after receipt of the notice to complete their applications. It is also our expectation that the entire claims process will, if possible, be completed and refunds made to eligible customers of Gulf within eighteen months after the period for filing claims begins.

Finally, a number of commenters have noted their interest in filing actions on behalf of classes of Gulf customers. Refund applications filed on behalf of groups of customers will be considered. We will not, however, prejudge the merits of such applications. Instead, applications that are submitted on behalf of a class will be evaluated on a case-by-case basis as received. In general, we will be guided in considering such applications by the requirements applicable to class actions set forth in Rule 23 of the Federal Rules of Civil Procedure.

It is therefore ordered, That:

The special refund procedures set forth in the Appendix to this Decision are hereby adopted by the Department of Energy for the purpose of achieving an equitable distribution of the refund which has been agreed to by Gulf Oil Corporation and the Special Counsel for Compliance in a Consent Order dated July 26, 1978.

Dated: July 13, 1979.

Melvin Goldstein,

Director, Office of Hearings and Appeals.

Notes

[1] In particular, the disallowance proceeding concerned the manner in which Gulf established the cost of foreign crude oil purchased from Gulf affiliates. Various aspects of the crude oil transfer pricing program have been discussed in several DOE Freedom of Information Act proceedings. *See e.g., Kerr-McGee Corporation; Standard Oil Company (Indiana),* 1 DOE Par. 80,155 (1977); *Gulf Oil Corporation,* 1 DOE Par. 80,103 (1977); *Sun Company, Inc.,* 4 FEA Par. 80,573 (1976); *Sun Oil Co.,* 3 FEA Par. 80,528 (1975). The program prescribes the standards that refiners are required to use in establishing the cost of imported crude oil purchased in transactions between affiliated entities and the standards that the DOE will use to disallow or to reallocate landed costs pursuant to 10 CFR 212.83(b).

[2] 39 FR 42,368 (1974). Prior to January 15, 1974, the refiner price rule was set forth in 6 CFR 150,355(b), and prior to November 1, 1973 in 6 CFR 150,358(a).

[3] The stated quantity does not include either the petroleum products produced by Gulf during that period and retained for its own use or exempt products sold by Gulf. In the Interim Decision issued in connection with the Special Redress Petition, exempt petroleum products and products consumed internally were included in the total amount of petroleum products over which the refund was allocated. That method of allocation was consistent with the manner in which the refiner price regulations required firms to allocate increased product costs. *See* 10 CFR 212.83. Nevertheless, the DOE is cognizant of the fact that the total amount of increased product costs cited in the NOPD issued to Gulf significantly exceeded the amount of the settlement. Therefore, consistent with the ultimate objective of the claims procedure, *i.e.* to compensate Gulf customers for actual injuries that they may have incurred, no allocation of the refund will be made in this case to exempt or internally consumed products. We will, on the other hand, include certain sales of crude oil by Gulf because Gulf's interaffiliate crude oil costs were included in computing the maximum prices utilized in these transactions. *See* 10 CFR 212.65; 10 CFR 212.183.

Some individuals who filed comments in the special redress proceeding stated their agreement in principle with the type of allocation proposed in the Interim Decision, but nevertheless indicated that some flexibility should be exercised in exceptional cases. We will do so in the context of individual applications for refunds and will consider whether unusual circumstances under which a particular purchaser obtained covered products from Gulf should lead us to depart from the specific standards established in this Decision.

[4] In view of the possibility of *pro rata* reductions of approved claims, we intend to delay paying any refunds until all claims in a particular stage of the proceeding have been processed.

[5] An amount agreed upon in settlement of a judicial action shall be treated like a final judgment, provided that the DOE Office of Special Counsel approves the settlement which must be made within 15 months from the date of publication of this Decision and Order in the Federal Register.

Appendix

Special Refund Procedures

1. *Custody of Funds.* The Office of Hearings and Appeals (OHA) shall issue an order to Gulf Oil Corporation providing for the custody of the funds to be tendered pursuant to the Consent Order that the Special Counsel for Compliance of the Department of Energy entered into with Gulf Oil Corporation on July 26, 1978. The Order may, for example, require the establishment of special escrow accounts or may permit Gulf to retain the funds in a segregated interest-bearing account under the terms and conditions specified by the OHA. In the event Gulf is permitted to maintain the funds in a segregated account, Gulf shall disburse the funds only upon receipt of and in accordance with an order signed by the Director of the Office of Hearings and Appeals or his designee.

2. *Notice.* The Office of Hearings and Appeals shall publish an appropriate notice describing the procedures that shall be available to persons who wish to obtain a refund based on the Consent Order. A notice of this type shall be published in the Federal Register and in such other manner as the Office of Hearings and Appeals deems necessary or desirable. Other methods of publication may include press releases, advertisements in major newspapers and trade journals, and direct mailings to Gulf customers and to trade and consumer organizations.

3. *Application for Refund; Filing.* (a) After the date specified in the notice published pursuant to Section 2 any person who believes that he is entitled to a refund as a direct result of the pricing practices upon which the Consent Order was based may file an application for refund with the Office of Hearings and Appeals of the Department of Energy, 2000 M Street, NW., Washington, D.C. 20461, or at such other address as the Office of Hearings and Appeals may specify. Any application received before the date specified in the notice will not be considered unless it is resubmitted during the filing period. All applications must be signed by the applicant and should be labeled "Application for Refund—Gulf Oil Corporation Consent Order."

(b) Applications for refunds in excess of $100 must be filed in duplicate, and these applications will be available for public inspection in the Office of Hearings and Appeals, Public Docket Room at 2000 M Street, NW., Washington, D.C. Any applicant who believes that his application contains confidential information must so indicate on the first page of his application and submit two additional copies of his application from which the information that the applicant claims is confidential has been deleted. A statement must also be provided specifying why any such information is privileged or confidential.

(c) Any person that has obtained a final judgment against Gulf after a trial in a court of competent jurisdiction for a claim arising out of alleged overstatements of landed crude oil costs by Gulf during the period August 19, 1973, through January 31, 1976, may submit a refund application based on that judgment. Gulf may also submit an application for refund pursuant to these rules on behalf of any person who has obtained a final judgment against Gulf or with whom it has signed a settlement agreement for the type of claims referred to in the previous sentence. With respect to any such final judgment or settlement agreement, however, an application for refund may be filed only if the terms, conditions, and amount specified in the judgment or settlement agreement have been approved by the Special Counsel. Applications filed by Gulf pursuant to this subsection shall be considered as having been filed in a timely manner if they are filed within 15 months of the date of publication of these rules in the Federal Register.

4. *Time for Filing Applications.* An application for refund must be filed during the period that the Office of Hearings and Appeals specifies in the notice issued pursuant to Section 2. No applications received before the filing period or after the final deadline or extensions thereof will be considered. The filing period shall not be less than 180 days from the date of publication of the notice in the Federal Register. The Office of Hearings and Appeals may grant extensions of time in which to file applications for refunds for good cause shown. Requests for extensions of time must be in writing and submitted during the filing period.

5. *Contents of Application.* An application shall contain the following information:

(a) The name, address and telephone number of the applicant;

(b) A complete statement of the basis for the claim (including the applicant's Gulf account number and other identifying information);

(c) (i) The total quantity of covered petroleum products purchased directly from Gulf and (ii) the total quantity purchased from resellers of Gulf products during the period August 19, 1973 through January 31, 1976;

(d) With respect to each type of product the quantities, locations, periods of time during which the purchases were made, and if the product is motor gasoline or heating oil, whether it was for the applicant's personal use in his automobile or residence;

(e) Copies of all receipts, invoices, contracts, agreements, instruments or other documents necessary to establish the validity of the claim, including documents necessary to prove the quantities of covered Gulf petroleum products purchased during the period August 19, 1973 through January 31, 1976;

(f) A statement of whether the applicant has ever filed any other application for refund involving Gulf products with the Department of Energy and whether the applicant is currently or has been a party in any court proceeding involving alleged crude-oil pricing violations by Gulf; and

(g) A sworn statement signed by the applicant that all statements made in the application are true and correct to the best of his knowledge and belief.

In the alternative, an application may be filed by completing an appropriate form provided by the Department of Energy.

6. *Criteria for Evaluation.* (a) An application for refund shall be granted only if an applicant has persuasively demonstrated (i) the amount of covered Gulf petroleum products purchased during the August 19, 1973 through January 31, 1976 period, and (ii) (A) if the applicant is a reseller whose prices were subject to the regulations of the FEA or DOE during the relevant period, that it would not have been required to pass through to its customers a cost reduction equal to the refund claimed, or (B) if the applicant is a wholesale purchaser of Gulf products that is subject to federal, state or local regulation of rates or tariffs, that it has certified that it will notify each such regulatory agency of any refund it receives pursuant to these procedures.

(b) The amount of the refund to which a purchaser of Gulf products is entitled shall generally be determined by multiplying the volume in gallons of covered Gulf petroleum products purchased by $0.00122.

7. *Processing of Applications.* (a) The Director of the Office of Hearings and Appeals may appoint an administrator to evaluate applications under guidelines established by the Office of Hearings and Appeals. The administrator, if he is not a federal government employee, may be compensated from the funds referred to in the Consent Order. The administrator may design and distribute an optional application form for the convenience of the applicants.

(b) The Office of Hearings and Appeals or its designee may initiate an investigation of any statement made in an application and may require verification of any document submitted in support of a claim. The Office of Hearings and Appeals or its designee may solicit and accept submissions from interested persons, including Gulf Oil Corporation and the Office of Special Counsel for Compliance, relevant to any application. In evaluating an application, the Office of Hearings and Appeals or its designee may consider information obtained from any other source and may on its own initiative convene a hearing or conference if, in its discretion, it decides that a hearing or conference will advance its evaluation of an application.

(c) The Director of the Office of Hearings and Appeals or his designee shall conduct any hearing or conference that is convened with respect to an application for refund and will specify the time and place for the hearing or conference and notify the applicant. The official conducting the hearing may administer oaths and affirmations, rule on the presentation of information, receive relevant information, dispose of procedural requests, determine the format of the hearing, and otherwise regulate the course of the hearing.

8. *Decision of the Department of Energy.* Upon consideration of the application and other relevant information received or obtained during the course of the proceeding, the Director of the Office of Hearings and Appeals or his designee shall issue an order granting or denying the application. The order shall contain a concise statement of the relevant facts and the legal basis for the decision. A copy of the order, with such modification as is necessary to ensure the confidentiality of information protected from public disclosure by 18 U.S.C. 1905, shall be served upon the applicant and any person who participated in the proceeding.

9. *Effect of Failure to File Timely Application for Refund.* Any application not filed on a timely basis may be summarily dismissed, and the applicant shall not be entitled to any portion of the funds submitted pursuant to the Consent Order.

10. *Participation by Gulf Oil Corporation.* Gulf shall assist in the evaluation of applications for refund to the extent contemplated by the Consent Order, including submitting any documents or information that the Office of Hearings and Appeals or its designee determines is relevant to its evaluation of a claim. An applicant who has unsuccessfully requested information or documents from Gulf may submit to the Office of Hearings and Appeals a request that information or documents believed to be in the possession of Gulf Oil Corporation and necessary to the evaluation of his claim be furnished either to the Office of Hearings and Appeals or to the applicant. Gulf will be given an opportunity to comment on the request. After considerating the request and the comments of Gulf, the Office of Hearings and Appeals or its designee may issue an order granting the request if it determines that the requester seeks relevant and material evidence and that compliance with the request will not impose an unreasonable burden on Gulf. The Director of the Office of Hearings and Appeals or his designee may in an appropriate case order that Gulf be reimbursed from funds in the escrow account for the actual expenses incurred by Gulf in complying with the provisions of this section.

11. *Reserves.* (a) The Office of Hearings and Appeals shall establish a reserve from the account described in section 1 to provide payment of final court judgments or settlements of court actions. Gulf shall notify OHA within 15 months from the date of publication of these procedures in the Federal Register of any outstanding court actions involving claims based on the matters addressed in the Consent Order. The amount of the reserve for each pending action shall be jointly determined by Gulf and Special Counsel, subject to OHA approval. If Gulf and Special Counsel do not agree on the amount of a reserve or whether a court action is qualified for the establishment of a reserve within 16 months of the date of publication of these procedures in the Federal Register, an independent third party selected by OHA on the basis of recommendations from Gulf and Special Counsel shall make the necessary determinations.

(b) The Office of Hearings and Appeals may establish a reserve from the account described in section 1 to pay administrative expenses that cannot be precisely determined prior to the final disbursement of all refunds.

12. *Limitations.* (a) The aggregate amount of all refunds authorized by the Office of Hearings and Appeals shall not exceed the amount to be remitted pursuant to the Consent Order by Gulf Oil Corporation, plus interest accrued, reduced by any administrative costs and reserves authorized by the Office of Hearings and Appeals. In the event that the aggregate amount of the claims filed exceeds the amount remitted by Gulf, the Office of Hearings and Appeals shall first award refunds to all qualified applicants who are direct purchasers of covered Gulf products from Gulf Oil Corporation on a pro rata basis. After approved applications of direct purchasers have been refunded in full, all approved administrative expenses paid and authorized reserves established, all remaining funds shall be paid on a pro rata basis to indirect purchasers of Gulf products whose applications have been approved. The Office of Hearings and Appeals may delay payment of any refunds until all applications have been processed.

(b) If an action for judicial review of these procedures is filed within 30 days of their publication in the Federal Register challenging the authority of the DOE or the validity of the Decision and Order or any portion thereof, Gulf will not be obligated to pay any part of the Consent Order fund to claimants whose refunds are affected by the litigation until 15 days following final adjudication or other resolution of such judicial action.

13. *Interim and Ancillary Orders.* The Director of the Office of Hearings and Appeals or his designee may issue any interim or ancillary orders, or make any rulings or determinations necessary to ensure that the refund proceedings, including the operations of any administrator appointed in connection with these proceedings and any appeal procedures, are conducted in an appropriate manner and are not unduly delayed.

14. *Remaining Funds.* Any funds, including any accmulated interest, remaining in the account described in section 1 or any reserves after the disposition of all timely applications for refund and payment of

approved expenses of administering the refund procedures may be remitted to the United States pursuant to the Consent Order or distributed in any other manner as the Director of the Office of Hearings and Appeals deems appropriate.

15. *Reference to Decision.* The principles stated in the Decision and Order of the Office of Hearings and Appeals to which these rules are an Appendix shall be followed in construing the refund procedures.

16. *Amendments.* The procedures specified in this Appendix may be amended by Order of the Office of Hearings and Appeals. Any such amendment shall be published in the Federal Register.

[FR Doc. 79-22068 Filed 7-20-79; 8:45 am]

BILLING CODE 6450-01-M

ENVIRONMENTAL PROTECTION AGENCY

[FRL 1276-5]

Financial Assistance for Resource Recovery Project Development Under the President's Urban Policy Class Deviation; Correction

In Federal Register Document 79-18263, published on Tuesday, June 12, 1979, on page 33738, in the middle column, the deviation was inadvertently omitted and is published here. For Further Information Contact: Mr. Alexander J. Greene, Director, Grants Administration Division (PM-216), Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460 (Tel. No. 202 755-0850).

Dated: July 13, 1979.

C. William Carter,

Acting Assistant Administrator for Planning and Management.

ENVIRONMENTAL PROTECTION AGENCY

Dated: June 6, 1979.

Subject: Class Deviation from 40 CFR 35.716, Financial Assistance for Resource Recovery Project Development Under the President's Urban Policy.

From: Alexander J. Greene, Director, Grants Administration Division (PM-216).

To: Regional Administrators.

On October 17, 1978, EPA announced the procedures by which interested parties could apply for financial assistance for solid waste resource recovery project planning and feasibility analysis under the President's Urban Policy issued on March 27, 1978.

EPA is administering the Financial Assistance for Resource Recovery Project Development Under the President's Urban Policy program under section 4008(a)(2) of the Resource Conservation and Recovery Act of 1976 (RCRA). Accordingly, the regulations contained in 40 CFR Part 30, 40 CFR 35.400 through 35.425 and 40 CFR 35.700 through 35.744 will apply to all assistance awarded under this program.

The regulations in 40 CFR 35.700 through 35.744 were originally promulgated to apply to RCRA State program planning grants. 40 CFR 35.716 specifies that the budget period shall be for the Federal fiscal year. Grants awarded under the Financial Assistance for Resource Recovery Project Development Under the President's Urban Policy program will be project specific in that each grantee will be awarded funds to perform specific tasks relevant to their individual project needs and situations. The time required to perform these tasks will vary greatly from project to project, dependent on a variety of technical, legal, institutional, and political factors. It would not be practicable to require that the project timetables of these projects coincide with the Federal fiscal year.

I am approving a deviation from 40 CFR 35.716 to permit budget periods more appropriate to project specific assistance under the Financial Assistance for Resource Recovery Project Development Under the President's Urban Policy program. Each Regional Office must negotiate a budget period to coincide with the time required to complete the project objectives.

All other requirements of the 40 CFR Part 30, 40 CFR 35.400 through 35.425, and 40 CFR 35.700 through 35.744 regulations remain in full effect for the Financial Assistance for Resource Recovery Project Development Under the President's Urban Policy Program.

Dated: June 6, 1979.

Concur:

C. W. Carter,

Acting Assistant Administrator for Planning and Management.

Dated: May 11, 1979.

Concur:

Thomas C. Jorling,

Assistant Administrator for Water and Waste Management.

[FR Doc. 79-22709 Filed 7-20-79; 8:45 am]

BILLING CODE 6560-01-M

FEDERAL MARITIME COMMISSION

Leslie E. Still, Jr., et al.; Agreements Filed

The Federal Maritime Commission hereby gives notice that the following agreements have been filed with the Commission for approval pursuant to section 15 of the Shipping Act, 1916, as amended (39 Stat. 733, 75 Stat. 763, 46 U.S.C. 814).

Interested parties may inspect and obtain a copy of each of the agreements and the justifications offered therefor at the Washington Office of the Federal Maritime Commission, 1100 L Street, NW, Room 10423; or may inspect the agreements at the Field Offices located at New York, NY; New Orleans, Louisiana; San Francisco, California; Chicago, Illinois; and San Juan, Puerto Rico. Interested parties may submit comments on each agreement, including requests for hearing, to the Secretary, Federal Maritime Commission, Washington, D.C., 20573, on or before August 13, 1979 in which this notice appears. Comments should include facts and arguments concerning the approval, modification, or disapproval of the proposed agreement. Comments shall discuss with particularity allegations that the agreement is unjustly discriminatory or unfair as between carriers, shippers, exporters, importers, or ports, or between exporters from the United States and their foreign competitors, or operates to the detriment of the commerce of the United States, or is contrary to the public interest, or is in violation of the Act.

A copy of any comments should also be forwarded to the party filing the agreements and the statement should indicate that this has been done.

Agreement No. T-3300-1

Filing party: Leslie E. Still, Jr., Senior Deputy City Attorney, Harbor Branch Office, City Attorney of Long Beach, Harbor Administration Building, Post Office Box 570, Long Beach, California 90801

Summary: Agreement No. T-3300-1, between the Board of Harbor Commissioners of the City of Long Beach (City) and Universal Marine Corp. (Universal), modifies the parties' basic agreement which provides for the monthly lease of 8,415 square feet of land area and 68,700 square feet of water area located at Pier E, Long Beach, California, and used by Universal for the outfitting and repair of boats. The facilities are not used in connection with common carriers by water. The purpose of this amendment is to expand the land area of the leased premises to 29,604 square feet, including Harbor Department Building No. 244, and to increase the monthly rental to $1,520.00.

Agreement No. T-3635-1.

Filing party: Betty I. Crofoot, House Counsel, Port of Portland, Box 3529, Portland, Oregon 92708.

Summary: Agreement No. T-3635-1, between the Port of Portland (Port) and Fred F. Noonan Co., Inc. (Noonan) modifies the basic agreement between the Port and Noonan which provides that Nooonan will perform services relating to the receipt, inventory, and delivery of import vehicles at Terminal 6, Portland, Oregon for a certain mutually agreed to schedule of compensation. The purpose of the modification is to provide for increased payment by the Port to Noonan.

Agreement No. T-3825.

Filing party: Mr. William E. Daily, Assistant Attorney General, Offices of Attorney General, 219 State House, Indianapolis, Indiana 46204.

Summary: Agreement No. T-3825 between the Indiana Port Commission (Port) and Cargill Incorporated (Cargill), provides for the Port's construction and lease to Cargill of a new dock and grain handling facility at Burns Waterway Harbor. The Port shall issue and sell Port Revenue Bonds not to exceed $3,100,000 to finance construction of the facilities. As compensation, Cargill shall pay Port an amount sufficient to service the bond debt required to finance construction of the leased facilities. In addition, prior to Cargill's initiation of operations, Cargill shall pay Port $3,360 per month. After Cargill's initiation of operations, Cargill shall pay Port a total annual amount, including service of the bond debt, subject to a minimum of $268,000 and a maximum of $318,000 per annum. After payment and discharge of the outstanding bonds, Cargill shall have the option of purchasing from the Port for the sum of one dollar any or all of the leased improvements and/or the leased dock.

Agreement No. T-3829.

Filing party: Joe H. Hamner, Jr., Attorney, Board of Commissioners of the Port of New Orleans, Post Office Box 60046, New Orleans, Louisiana 70160.

Summary: Agreement No. T-3829, between the Board of Commissioners of the Port of New Orleans (Board) and Baton Rouge Marine Contractors, Inc. (BRMC) provides for the 10-year lease by the board to BRMC of a terminal facility, designated as France Road Terminal Berths 5 and 6, on a non-exclusive basis, to be operated as a public container and Ro/Ro terminal open to any and all shippers or receivers of cargo that may be suitably handled by the facility.

Agreement No. 10373.

Filing party: F. W. Krueger, Eckert Overseas Agency, Inc., 88 Pine Street, New York, New York 10005.

Summary: Agreement No. 10373 is an equipment interchange and lease agreement between Orient Overseas Container Line Ltd., and Associated Container Transportation, both common carriers by water in the foreign commerce of the United States. The parties agree to lease cargo containers and/or related equipment to each other subject to mutually acceptable terms, conditions, practices, and charges. By Order of the Federal Maritime Commission.

Dated: July 18, 1979.

Francis C. Hurney,

Secretary.

[FR Doc. 79-22649 Filed 7-20-79; 8:45 am]

BILLING CODE 6730-01-M

FEDERAL RESERVE SYSTEM

Bank Holding Co.; Proposed De Novo Nonbank Activities

The bank holding companies listed in this notice have applied, pursuant to section 4(c)(8) of the Bank Holding Company Act (12 U.S.C. section 1843(c)(8)) and section 225.4(b)(1) of the Board's Regulation Y (12 CFR 225.4(b)(1)), for permission to engage *de novo* (or continue to engage in an activity earlier commenced *de novo*), directly or indirectly, solely in the activities indicated, which have been determined by the Board of Governors to be closely related to banking.

With respect to each application, interested persons may express their views on the question whether consummation of the proposal can "reasonably be expected to produce benefits to the public, such as greater convenience, increased competition, or gains in efficiency, that outweigh possible adverse effects, such as undue concentration of resources, decreased or unfair competition, conflicts of interest, or unsound banking practices." Any comment on an application that requests a hearing must include a statement of the reasons a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute, summarizing the evidence that would be presented at a hearing, and indicating how the party commenting would be aggrieved by approval of that proposal.

Each application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank indicated for that application. Comments and requests for hearings should identify clearly the specific application to which they relate, and should be submitted in writing and received by the appropriate Federal Reserve Bank not later than August 15, 1979.

A. *Federal Reserve Bank of Chicago,* 230 South LaSalle Street, Chicago, Illinois 60690:

Banks of Iowa, Inc., Cedar Rapids, Iowa (mortgage banking and insurance activities; Iowa, Nebraska): to engage, through its subsidiary, BI Mortgage Company, Inc., in making, acquiring and servicing real estate loans for its own account or the account of others and acting as agent or broker in the sale of credit life and credit accident and health insurance that is directly related to extensions of credit by BI Mortgage Company and the subsidiary banks of Banks of Iowa, Inc. These activities would be conducted from offices in Cedar Rapids, Iowa and Omaha, Nebraska, serving Cedar Rapids, Ottuma, Des Moines, Council Bluffs, Burlington, Dubuque, Sioux City, Davenport, Hiawatha County and Marion County, Iowa and Douglas County and Sarpy County, Nebraska.

B. *Other Federal Reserve Banks:* None.

Board of Governors of the Federal Reserve System, July 17, 1979.

Edward T. Mulrenin,

Assistant Secretary of the Board.

[FR Doc. 79-22664 Filed 7-20-79; 8:45 am]

BILLING CODE 6210-01-M

Federal Open Market Committee; Domestic Policy Directive of May 22, 1979

In accordance with § 271.5 of its rules regarding availability of information, there is set forth below the Committee's Domestic Policy Directive issued at its meeting held on May 22, 1979.[1]

The information reviewed at this meeting suggests a moderate pickup in growth of real output of goods and services in the current quarter from the sharply reduced pace in the first quarter, when public and private construction activity was adversely affected by unusually severe weather. In April, however, industrial production declined and growth in nonfarm payroll employment slowed, in large part owing to effects of a work stoppage in the trucking industry early in the month. The unemployment rate, at 5.8 percent, remained at about the level prevailing earlier in the year. The dollar value of total retail sales rose somewhat in April, although apparently by less than the increase in average prices. Over recent months, broad measures of prices have increased at a faster pace than during 1978, and the index of average hourly earnings has continued to rise rapidly.

Demand for the dollar has continued strong in exchange markets over the past five weeks, and the trade-weighted value of the dollar against major foreign currencies has risen further. The U.S. trade deficit declined further in March and was slightly lower in the first quarter as a whole than in the fourth quarter of 1978.

M-1 expanded sharply in April, after having declined in the first quarter, and M-2 and M-3 grew rapidly. The interest-bearing component of M-2 also grew rapidly, following several months of slow growth, as net flows into money market certificates at commercial banks increased while outflows of savings deposits slowed. At nonbank thrift institutions, net flows into money market certificates moderated, and overall inflows of funds receded from the already reduced pace of the first quarter. Since mid-April, short-term market interest rates have changed little, on balance; most longer-term rates have increased.

Taking account of past and prospective developments in employment, unemployment, production, investment, real income, productivity, international trade and payments, and prices, it is the policy of the Federal Open Market Committee to foster monetary and financial conditions that will resist inflationary pressures while encouraging moderate economic expansion and contributing to a sustainable pattern of international transactions. At its meeting on February 6, 1979, the Committee agreed that these objectives would be furthered by growth of M-1, M-2, and M-3 from the fourth quarter of 1978 to the fourth quarter of 1979 within ranges of 1½ to 4½ percent, 5 to 8 percent, and 6 to 9 percent respectively. The

[1] The Record of Policy Actions of the Committee for the meeting of May 22, 1979, is filed as part of the original document. Copies are available on request to the Board of Governors of the Federal Reserve System, Washington, D.C. 20551.

associated range for bank credit is 7½ to 10½ percent. These ranges will be reconsidered in July or at any time as conditions warrant.

In the short run, the Committee seeks to achieve bank reserve and money market conditions that are broadly consistent with the longer-run ranges for monetary aggregates cited above, while giving due regard to the program for supporting the foreign exchange value of the dollar and to developing conditions in domestic financial markets. Early in the period before the next regular meeting, System open market operations are to be directed at maintaining the weekly average federal funds rate at about the current level. Subsequently, operations shall be directed at maintaining the weekly average federal funds rate within the range of 9¾ to 10½ percent. In deciding on the specific objective for the federal funds rate the Manager shall be guided mainly by the relationship between the latest estimates of annual rates of growth in the May-June period of M-1 and M-2 and the following ranges of tolerance: 0 to 5 percent for M-1 and 4 to 8½ percent for M-2. If, with approximately equal weight given to M-1 and M-2, their rates of growth appear to be close to or beyond the upper or lower limits of the indicated ranges, the objective for the funds rate is to be raised or lowered in an orderly fashion within its range.

If the rates of growth in the aggregates appear to be above the upper limit or below the lower limit of the indicated ranges at a time when the objective for the funds rate has already been moved to the corresponding limit of its range, the Manager will promptly notify the Chairman, who will then decide whether the situation calls for supplementary instructions from the Committee.

Note.—On June 15, the Committee modified the domestic policy directive adopted at its meeting on May 22, 1979, to call for open market operations directed at maintaining the weekly average federal funds rate at about 10¼ percent.

By order of the Federal Open market Committee, July 13, 1979.

Murray Altmann,

Secretary.

[FR Doc 79-22653 Filed 7-20-79; 8:45 am]

BILLING CODE 6210-01-M

National City Corp.; Acquisition of Banks

National City Corporation, Cleveland, Ohio, has applied for the Board's approval under section 3(a)(3) of the Bank Holding Company Act (12 U.S.C. section 1842(a)(3)) to acquire 100 percent of the voting shares (less director's qualifying shares) of the successor by merger to the National City Bank of Marion, Marion Ohio and 100 percent (less directors' qualifying shares) of the voting shares of the successor by merger to The Citizens National Bank, Bryan, Ohio. The factors that are considered in acting on the applications are set forth in section 3(c) of the Act (12 U.S.C. section 1842(c)).

The applications may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Cleveland. Any person wishing to comment on the applications should submit views in writing to the Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551, to be received not later than August 13, 1979. Any comments on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, July 12, 1979.

Edward T. Mulrenin,

Assistant Secretary of the Board.

[FR Doc. 79-22655 Filed 7-20-79 8:45 am]

BILLING CODE 6210-01-M

National City Corp.; Acquisition of Bank

National City Corporation, Cleveland, Ohio, has applied for the Board's approval under section 3(a)(3) of the Bank Holding Company Act (12 U.S.C. section 1842(a)(3)) to acquire 100 percent of the voting shares (less directors' qualifying shares) of the successor by merger to The Fairfield National Bank, Lancaster, Ohio. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. section 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Cleveland. Any person wishing to comment on the application should submit views in writing to the Reserve Bank to be received not later than August 13, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, July 12, 1979.

Edward T. Mulrenin,

Assistant Secretary of the Board.

[FR Doc. 79-22656 Filed 7-20-79; 8:45 am]

BILLING CODE 6210-01-M

Osceola Bancorporation, Inc.; Formation of Bank Holding Co.

Osceola Bancorporation, Inc., Osceola, Wisconsin, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. section 1842(a)(1)) to become a bank holding company by acquiring 92.2 percent or more of the voting shares of Bank of Osceola, Osceola, Wisconsin. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. section 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Minneapolis. Any person wishing to comment on the application should submit views in writing to the Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551 to be received no later than August 15, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, July 16, 1979.

Edward T. Mulrenin,

Assistant Secretary of the Board.

[FR Doc. 79-22657 Filed 7-20-79; 8:45 am]

BILLING CODE 6210-01-M

Security Bancshares Co.; Formation of Bank Holding Co.

Security Bancshares Co., Glencoe, Minnesota, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. section 1842(a)(1)) to become a bank holding company by acquiring 80 percent or more of the voting shares of Security State Bank of Glencoe, Glencoe, Minnesota, and the First State Bank of Brownton, Brownton, Minnesota. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. section 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Minneapolis. Any person wishing to comment on the application should submit views in writing to the Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551 to be received no later than August 15, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, July 16, 1979.

Edward T. Mulrenin,

Assistant Secretary of the Board.

[FR Doc. 79-22658 Filed 7-20-79; 8:45 am]

BILLING CODE 6210-01-M

Summit Bancshares, Inc., Formation of Bank Holding Company

Summit Bancshares, Inc., Fort Worth, Texas, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. section 1842(a)(1)) to become a bank holding company by acquiring 100 per cent of the voting shares of Summit National Bank, Fort Worth, Texas. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. section 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Dallas. Any person wishing to comment on the application should submit views in writing to the Reserve Bank, to be received not later than August 2, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, July 13, 1979.

Edward T. Mulrenin,

Assistant Secretary of the Board.

[FR Doc. 79-22659 Filed 7-20-79; 8:45 am]

BILLING CODE 6210-01-M

GENERAL SERVICES ADMINISTRATION

[GSA Order APD 2800.1 Dated January 30, 1979]

Contract Clearance

AGENCY: General Services Administration.

ACTION: Contract clearance procedures.

SUMMARY: This order establishes the requirements and procedures for contract clearance in the General Services Administration. It provides that contract actions above certain specific dollar thresholds be submitted for pre-award clearance. These actions will be reviewed by the Assistant Administrator for Acquisition Policy.

EFFECTIVE DATE: The effective date of this order is April 15, 1979.

Dated: July 12, 1979.

Dale R. Babione,

Assistant Administrator for Acquisition Policy.

General Services Administration.

Washington, D.C. 20405

[APD 2800.1]

January 30, 1979.

GSA Order

Subject: Contract clearance.

1. *Purpose.* This order establishes the requirements and procedures for contract clearance in GSA.

2. *Applicability.* This order is applicable to ADTS, FSS and PBS.

3. *Summary of attachment.* The attachment sets forth the requirements and procedures for clearance of contracts by the Assistant Administrator for Acquisition Policy. It lists the types of contractual actions requiring such clearance and includes details on how to process contractual actions for the requisite clearance. In addition, ADTS, FSS and PBS are required to establish contract clearance offices in their Central Offices and perform the clearance function for both regional and Central Office procurements. Each service shall establish clearance requirements to provide for pre-award review of contractual actions (including those requiring clearance by the Assistant Administrator for Acquisition Policy) representing approximately 80% of forecasted obligations for a fiscal year.

4. *Revision of contract clearance criteria and procedures.* Specific contract clearance criteria and procedures may be revised when the Office of Acquisition Policy, GSA, becomes fully operational and thereafter as required to further GSA acquisition policy objectives.

5. *Implementating actions.* ADTS, FSS and PBS shall develop written procedures implementing this order with respect to service performance of the contract clearance function. A copy of these procedures shall be sent to the Office of Acquisition Policy by the effective date of this order.

6. *Effective date.* This order is effective on April 15, 1979. Contractual actions to be awarded after April 14, 1979, which meet the criteria of paragraph 2 of the attachment or the criteria to be established by the services pursuant to paragraph 3 of the attachment shall be subject to the provisions of this order.

Dale R. Babione,

Assistant Administrator for Acquisition Policy.

[APD 2800.1]

Attachment

January 30, 1979

1. *General.* Each proposed contractual document and supporting file shall be reviewed by the contracting officer prior to signing the contractual document and prior to forwarding the contract and file for review by higher authority within the service and any required clearance by the Assistant Administrator for Acquision Policy. The contracting officer is responsible for the completeness and accuracy of the contractual document and its supporting file. Each contract file shall contain all pertinent information applicable to the proposed award. The information included in the contract file shall be in sufficient detail to permit reconstruction of all singificant events by any subsequent reviewer without referrals to the individuals responsible for the contractual actions.

2. *Contractual actions requiring clearance by the Assistant Administrator for Acquisition Policy prior to award.* a. The contractual actions listed in c. below require the approval of the Assistant Administrator for Acquisition Policy prior to award. The term "contractual actions" as used here means:

(1) Contracts for supplies and non-personal services, including contracts for construction, alteration and repair, and leasing.

(2) Modifications to existing contracts which are beyond the scope of the contracts, including modifications for the exercise of options (or, in case of a lease, an additional term of the lease).

(3) Definitive contracts superseding letter contracts; however, letter contracts do not require clearance.

b. For clearance purposes, the dollar value of a contractual action is the sum of the estimated or actual dollar amount of obligations and the amount of any option (or, in case of a lease, the full term of the lease) included in the action. The estimated or actual dollar obligations includes those to be made by GSA and other agencies ordering under GSA-awarded contracts.

c. The following contractual actions (including actions to be awarded by regional offices) shall be submitted to the Contract Clearance Directorate for clearance:

(1) Actions resulting from invitation for bids, including Small Business Restricted Advertising, when award is proposed to a sole responsive and responsible bidder and the total dollar value of the sole bid items to be awarded exceeds $500,000.

(2) For ADTS:

(a) Negotiated actions for teleprocessing services schedules exceeding $10,000,000.

(b) Negotiated actions for ADP schedules exceeding $4,000,000.

(c) All other negotiated actions exceeding $2,000,000.

(3) For FSS, all negotiated actions exceeding $3,500,000.

(4) For PBS, all negotiated actions exceeding $1,000,000.

3. *ADTS, FSS and PBS contract clearance.* a. ADTS, FSS and PBS shall establish and maintain requirements and procedures for clearance of contractual actions prior to award. The requirements for clearance shall include those contractual actions (including actions to be awarded by counterpart regional services) to be sent to the Assistant

Administrator for Acquisition Policy as well as other contractual actions to be awarded either by the Central Office or counterpart regional services. With respect to such other contractual actions, each service shall determine the scope of the clearance requirements. However, the clearance requirements so established shall provide that contractual actions representing approximately 80% of the forecasted dollar obligations for a fiscal year will be cleared by the Service prior to award.

(1) The value of the contractual actions to be cleared by the Assistant Administrator for Acquisition Policy is included in the 80% criteria.

(2) The forecasted dollar obligations include those to be made by the GSA and other agencies ordering Under GSA-awarded contracts.

(3) For FY 1979 the 80% threshold shall apply only to those contractual actions awarded between the effective date of this order and the end of the fiscal year.

(4) The clearance requirements shall include a representative number of actions, including sole bids in response to IFBs, sole offers under negotiated solicitations, and complex and high dollar value actions.

In addition, randomly selected contractual actions should be reviewed on a post award basis.

b. ADTS, FSS and PBS shall take the actions necessary to establish a contract clearance office in their Central Offices to perform the clearance function. The contract clearance office should be an organizational element of the service's office of acquisition/contracting. The clearance function shall be performed as full-time duty by a staff sufficient for the purpose. The personnel selected to perform the contract clearance should possess the qualifications required of contracting officers as set forth in FPR 1-1.404 and have demonstrated technical proficiency in the contracting field and the capability for exercising sound business judgment.

c. The contract clearance office shall throughly review each contractual action submitted to assure conformance with applicable laws, regulations, and established policies and procedures. Particular attention should be given to the business aspects, including the pricing, of the contractual actions. The contract clearance office shall serve as the service's contact point with the contract Clearance Directorate and furnish any additional required information or clarification which may be necessary in processing contractual actions requiring clearance by the Assistant Administrator for Acquisition policy.

d. All contractual actions sent to the Assistant Administrator for Acquisition Policy shall be transmitted by memorandum signed by the head of the service office of acquisition/contracting. The memorandum shall indicate that the particular contractual action has been thoroughly reviewed, and conforms to all applicable laws and regulations, established policies and procedures. It shall include the service's recommendations for approval by the Assistant Administrator for Acquisition policy.

4. *Concurrence of Counsel.* Contractual actions to be submitted to the Assistant Administrator for Acquisition Policy for clearance shall have the prior concurrence for legal sufficiciency of the appropriate Assistant General Counsel in the Central Office. Evidence of such concurrence shall be made a part of the supporting contract file.

5. *Information to be furnished with contractual actions submitted to the Assistant Administrator for Acquisition Policy.* a. The complete contract file supporting the contractual action shall be forwarded. In addition, a duplicate file for retention by the Contract Clearance Directorate shall also be sent.

b. The information and documents listed below are those which are normally required as support for an advertised or negotiated contract. These should be included in the contract file in the order indicated; i.e., starting with the lowest number. Not all information and documents will be applicable to every contractual action. Conversely, other information and documents may be applicable to specific contractual actions and the contracting officer should include such items in the contract file in proper sequence in the contracting cycle. An index of the contents of the file should be prepared and placed on the top of the file. In addition, each item should be tabbed and, if more than one document is included under a tab, they should be filed chronologically with the most recent document on top.

(1) Requisition or request for contractual action. The basic acquisition authority and all changes thereto should be filed under this tab. Documentations supporting and authorizing any differences between supplies or services called for in the contractual document and the acquisition authority must also be filed under this tab.

(2) Specifications, drawings or other descriptive material of the supplies or services being acquired. If specifications and drawings are too voluminous for inclusion in the file, Tab 2 should then include a brief description of the supplies or services being acquired and a statement identifying the Central Office or regional service file containing the specifications and drawings.

(3) Acquisition plan.

(4) Determinations and findings. Determinations and findings required by Subparts 1-3.2 and 1-3.3 of the FPR shall be included under this tab.

(5) Department of Labor Wage Determination.

(6) Small business and labor surplus area determinations.

(7) Source list.

(8) Statement as to synopsis of proposed procurement pursuant to FPR 1-1.1003.

(9) Pre-invitation notice.

(10) IFB/RFP and amendments.

(11) Abstract of bids/proposals.

(12) Cost or pricing data. Where the requirement for submission of cost or pricing data is waived as provided in FPR1-3.807.3, the waiver and documentation supporting the waiver shall be filed under this tab.

(13) Audit report. Where the requirement for an audit of a price proposal is waived as provided in FPR 1-3.809, the waiver and documentation supporting the waiver shall be filed under this tab. Reports of technical analysis required in support of audit reports shall be filed under this tab.

(14) Price or cost analysis report prepared pursuant to FPR 1-3.807-2. Supporting technical analyses, other than those supporting an audit report, shall be filed under this tab. The profit or fee analyses required by FPR 1-3.808 shall be made a part of the price or cost analysis report.

(15) Price negotiation memorandum required by FPR 1-3.811 shall be filed under this tab. This memorandum must be written so as to permit reconstruction of all of the major considerations of the acquisition.

(16) Certificate of current cost or pricing data.

(17) Pre-award survey.

(18) EEO compliance review.

(19) No bid or no proposal correspondence.

(20) Unsuccessful bids or proposals. Unsuccessful bids or proposals need not be included in the file if too voluminous, provided that an abstract of bids/proposals is included in the file. However, a copy of each rejected bid or each unacceptable proposal must be included in the file under this tab.

(21) Mistakes in bids. All correspondence and determinations relating to mistakes in bids disclosed prior to award shall be filed under this tab.

(22) Actions taken on late bids or proposals.

(23) Successful bid or proposal and all pertinent correspondence applicable to the contractual action.

(24) Contractual action. The contractor's copy and the copy for the official contract file shall be submitted. Where an award is to be accomplished by use of the Award portion of the SF 33, or similar forms, the contract document shall be included in Tab 23.

(25) Evidence of concurrence for legal sufficiency of the appropriate Assistant General Counsel in the Central Office.

(26) Any service required approvals.

6. *Manual approval of contractual actions.* a. Manual approval of contractual actions shall be accomplished in accordance with the following procedure:

(1) Any solicitation expected to result in a negotiated contract or contract modification which requires the approval of the Assistant Administrator for Acquisition Policy prior to award shall include the following provision:

Approval of Contractual Action

This contractual action shall be subject to the written approval of the Assistant Administrator for Acquisition Policy, General Services Administration, and shall not be binding until so approved.

(2) This provision shall be included in negotiated contractual documents when the solicitation document is not to be made a part of the resulting contract or modification, or when the provision has not been included in the solicitation.

(3) The Assistant Administrator's approval of a contractual action shall be located on the face of the contractor's copy of the contract or modification and on the copy for the official contract file.

b. Contractual actions requiring only service approval prior to award shall also be subject to manual approval. Each service shall designate the officials in its Central Office who are authorized to manually approve such contractual actions. The above provision and procedures, appropriately modified for this purpose, shall be used.

7. *Clearance, conditional clearance or return of contractual actions.* a. Contractual actions approved by the Assistant Administrator for Acquisition Policy shall be promptly returned to the service by the Contract Clearance Directorate. If the approval of a contractual action is conditional (i.e., subject to satisfying certain conditions), such conditional approval shall be documented in a memorandum to the service signed by the Assistant Administrator. The stated conditions must be satisfied prior to consummating the award.

b. Contractual actions requiring clearance by the Assistant Administrator for Acquisition Policy which are not approved shall be returned to the cognizant service. The memorandum of transmittal shall set forth the reasons for the return and be signed by the Assistant Administrator for Acquisition Policy.

c. The service contract clearance office shall advise the Director, Contract Clearance Directorate, in writing, of any contractual action which was cleared by the Assistant Administrator for Acquisition Policy but was not awarded. A complete explanation for the failure to make award shall also be provided.

8. *Post award contract review.* a. The Contract Clearance Directorate shall perform contract reviews on a post award basis. The Director, Contract Clearance Directorate shall select the contractual actions to be reviewed on this basis.

b. The results of post award reviews performed by the Contract Clearance Directorate shall be provided to the service's office of acquisition/contracting.

[FR Doc. 22679 Filed 7-20-79 8:45 am]
BILLING CODE 6820-61-M

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Office of Education

Educational Opportunity Centers; Closing Date for Transmittal of Applications for Fiscal Year 1980

Applications are invited for new projects under the Educational Opportunity Centers Program.

Authority for this program is contained in section 417B of the Higher Education Act of 1965, as amended.

(20 U.S.C. 1070d-1)

This program issues awards to institutions of higher education, combinations of institutions of higher education, public and private agencies and organizations, and, in exceptional cases, secondary schools and secondary vocational schools.

The purpose of the awards is to assist applicants to carry out projects that serve areas with major concentrations of low-income populations by providing, in coordination with other applicable programs and services: information concerning financial and academic support for persons living in the area who desire to pursue a program of postsecondary education; counseling, tutorial and other necessary services to such persons while attending postsecondary institutions; and, assistance in applying for admission to postsecondary institutions, including assistance in preparing necessary applications for use by admission and financial aid officers.

Closing Date for Transmittal of Applications: Applications for new awards must be mailed or hand delivered by October 31, 1979.

Applications Delivered By Mail: An application sent by mail must be addressed to the U.S. Office of Education, Application Control Center, Attention: 13.543, Washington, D.C. 20202.

Proof of mailing must consist of:

(1) Legible U.S. Postal Service dated postmark;

(2) Legible mail receipt with the date of mailing stamped by the U.S. Postal Service; or

(3) Any other evidence acceptable to the Commissioner, such as dated shipping label, invoice, or receipt from a commercial carrier.

Private metered postmarks or mail receipts will not be accepted without a legible date stamped by the U.S. Postal Service.

Note.—The U.S. Postal Service does not uniformly provide a dated postmark. Applicants should check with their local post office before relying on this method.

Applicants are encouraged to use registered or at least first class mail.

Each late applicant will be notified that its application will not be considered.

Applications Delivered By Hand: An application that is hand delivered must be taken to the U.S. Office of Education, Application Control Center, Room 5673, Regional Office Building 3, 7th and D Streets, S.W., Washington, D.C.

The Application Control Center will accept hand-delivered applications between 8:00 a.m. and 4:30 p.m. (Washington, D.C., time) daily, except Saturdays, Sundays, and Federal holidays.

Applications that are hand delivered will not be accepted after 4:30 p.m. on the closing date.

Program Information: The applications for new grants will be evaluated competitively under the published funding criteria for new awards—45 CFR 154.5(c). All applications for FY 1980 funds will be treated as new applications. Successful applicants will receive up to two (2) year project period grants.

The Office of Education may not fund an applicant for a period of time longer than is requested by the applicant in the application. Applicants requesting two years of funding must submit a detailed work program and budget for the first year and an outline of the work program and a budget summary for the second year.

The Commissioner approves requests for the second year if:

1. The need continues to exist for the services provided by the project;

2. Satisfactory progress has been made in implementing the approved work plan and in achieving the project's goals and objectives;

3. The project continues to offer promise of success;

4. All required reports have been received and accepted by the Commissioner; and

5. Funds are available to continue the project.

An Application Preparation Workshop(s) will be conducted this Fall. For the time and location of this workshop(s), contact the Program Development Branch (see address in section on Further Information). Date(s) and location(s) will also be published in the Notices section of the Federal Register.

Available Funds: Approximately $130,000,000 is anticipated to be available for the Special Programs for Students from Disadvantaged Backgrounds in FY 1980. Of this amount it is estimated that $6,300,000 will be available for the Educational Opportunity Centers programs, to fund approximately 27 grants averaging $233,000. The breakdown for new awards in the other Special Programs is estimated to be $51,000,000 for Upward Bound, with approximately 390 grants averaging $130,700; $15,300,000 for Talent Search, with approximately 160 grants averaging $95,600; and $45,000,000 for Special Services, with approximately 484 grants averaging $93,000.

The processing of applications for these new projects will be subject to the availability of funds. These estimates do not bind the U.S. Office of Education except as may be required by the applicable statute and regulations.

Application Forms: Application forms and program information packages are expected to be ready for mailing August 13, 1979. They may be obtained by writing to the Division of Student Services and Veterans Programs, Information Systems and Program Support Branch, U.S. Office of Education, (Room 3514, Regional Office Building 3), 400 Maryland Avenue, S.W., Washington, D.C. 20202.

Applications must be prepared and submitted in accordance with the regulations, instructions, and forms included in the program information packages. The Commissioner suggests that the narrative portion of the application not exceed fifty (50) pages in length. The Commissioner further suggests that only the information required by the application form be submitted.

Applicable Regulations: The regulations applicable to this program are:

(a) regulations governing the Educational Opportunity Centers Program (45 CFR Part 154), and

(b) Office of Education General Provisions Regulations (45 CFR Parts 100 and 100a).

However, it is expected that the grant awards made under this program will be subject to the post award provisions of the Education Division General Administrative Regulations (EDGAR). EDGAR was published in proposed form in the Federal Register on May 4, 1979 (44 FR 26298). When published in final, EDGAR will supersede the Office of Education General Provisions Regulations.

Further Information: For further information contact the Program Development Branch, Division of Student Services and Veterans Programs, U.S. Office of Education (Room 3514, Regional Office Building 3), 400 Maryland Avenue, S.W., Washington, D.C. 20202, Telephone: (202) 245-2511.

(20 U.S.C. 1070d-1070d-1)

(Catalog of Federal Domestic Assistance Number 13.543: Educational Opportunity Centers)

Dated: July 17, 1979.

Mary Berry,

Acting Commissioner of Education.

[FR Doc 79-22703 Filed 7-20-79; 8:45 am]

BILLING CODE 4110-02-M

Special Services for Disadvantaged Students; Closing Date for Transmittal of Applications for Fiscal Year 1980

Applications are invited for new projects under the Special Services for Disadvantaged Students Program. Applications for National Demonstration projects will not be accepted at this time. A separate Notice of Closing Date will be published at a later date.

Authority for this program is contained in section 417B of the Higher Education Act of 1965, as amended.

(20 U.S.C. 1070d-1)

This program issues awards to institutions of higher education and combinations of institutions of higher education.

The purpose of the awards is to assist applicants to carry out projects designed to provide remedial and other special services for students with academic potential who are enrolled or accepted for enrollment at an institution which is a beneficiary of a Special Services grant and who by reason of deprived educational, cultural, or economic background, or physical handicap, or limnited English-speaking ability, are in need of such services to assist them to inititate, continue, or resume their postsecondary education.

Closing date for transmittal of applications: Applications for new awards must be mailed or hand delivered by October 22, 1979.

Applications delivered by mail: An application sent by mail must be addressed to the U.S. Office of Education, Application Control Center, Attention: 13.482, Washington, D.C. 20202.

Proof of mailing must consist of: (1) Legible U.S. Postal Service dated postmark;

(2) Legible mail receipt with the date of mailing stamped by the U.S. Postal Service; or

(3) Any other evidence acceptable to the Commissioner, such as dated shipping label, invoice, or receipt from a commercial carrier.

Private metered postmarks or mail receipts will not be accepted without a legible date stamped by the U.S. Postal Service. (Note.—The U.S. Postal Service does not uniformly provide a dated postmark. Applicants should check with their local post office before relying on this method.) Applicants are encouraged to use registered or at least first class mail.

Each late applicant will be notified that its application will not be considered.

Applications delivered by hand: An application that is hand delivered must be taken to the U.S. Office of Education, Application Control Center, Room 5673, Regional Office Building 3, 7th and D Streets, S.W., Washington, D.C.

The Application Control Center will accept hand-delivered applications between 8:00 a.m. and 4:30 p.m. (Washington, D.C., time) daily, except Saturdays, Sundays, and Federal holidays.

Applications that are hand delivered will not be accepted after 4:30 p.m. on the closing date.

Program information: The applications for new grants will be evaluated competitively under the published funding criteria for new awards—45 CFR 157.6(c). All applications for fiscal year 1980 funds will be treated as new applications. Successful applicants will receive up to four (4) year project period grants.

The Office of Education may not fund an applicant for a period of time longer than is requested by the applicant in the application. Applicants requesting more than one year of funding must submit a detailed work program and budget for the first year and an outline of the work program and a budget summary for each of the additional years.

The Commissioner approves requests for subsequent years if: (1) The need continues to exist for the services provided by the project;

(2) Satisfactory progress has been made in implementing the approved work plan and in achieving the project's goals and objectives;

(3) The project continues to offer promise of success;

(4) All required reports have been received and accepted by the Commission; and

(5) Funds are available to continue the project.

An Application Preparation Workshop(s) will be conducted this Fall. For the time and location of this workshop(s) contact the Program Development Branch (see address in section of Further Information). Date(s) and location(s) will also be published in the Notices section of the Federal Register.

Available funds: Approximately $130,000,000 is anticipated to be available for the Special Programs for Students from Disadvantaged Backgrounds in FY 1980. The breakdown for new awards is estimated to be $51,000,000 for Upward Bound, with approximately 390 grants averaging $130,700; $15,300,000 for Talent Search, with approximately 160 grants averaging $95,000; and $45,000,000 for Special Services, with approximately 484 grants averaging $93,000. The Educational Opportunity Centers program will be allocated $6,300,000 to fund approximately 27 grants averaging $233,000.

The processing of applications for new projects will be subject to the availability of funds. These estimates do not bind the U.S. Office of Education except as may be required by the applicable statute and regulations.

Application forms: Application forms and program information packages are expected to be ready for mailing by August 13, 1979. They may be obtained by writing to the Division of Student Services and Veterans Programs, Information Systems and Program Support Branch, U.S. Office of Education (Room 3514, Regional Office Building 3), 400 Maryland Avenue, S.W., Washington, D.C. 20202.

Applications must be prepared and submitted in accordance with the regulations, instructions, and forms included in the program information packages. The Commissioner suggest that the narrative portion of the application not exceed fifty (50) pages in length. The Commissioner further suggests that only the information required by the application form be submitted.

Applicable regulations: The regulations applicable to this program are: (a) regulations governing the Special Services Program (45 CFR Part 157); and

(b) Office of Education General Provisions Regulations (45 CFR Parts 100 and 100a).

However, it is expected that the grant awards made under this program will be subject to the post award provisions of the Education Division General Administrative Regulations (EDGAR). EDGAR was published in proposed form in the Federal Register on May 4, 1979 (44 FR 26298). When published in final, EDGAR will supersede the Office of Education General Provisions Regulations.

Further information: For further information contact the Program Development Branch, Division of Student Services and Veterans Programs, U.S. Office of Education (Room 3514, Regional Office Building 3), 400 Maryland Avenue, S.W., Washington, D.C., 20202, Telephone (202) 245-2511.

(20 U.S.C. 1070d-1070d-1)

(Catalog of Federal Domestic Assistance Number 13.482, Special Services for Disadvantaged Students)

Dated: July 17, 1979.

Mary Berry

Acting U.S. Commissioner of Education.

[FR Doc. 79-22701 Filed 7-20-79; 8:45 am]

BILLING CODE 4110-02-M

Talent Search; Closing Date for Transmittal of Applications for Fiscal Year 1980

Applications are invited for new projects under the Talent Search Program. Applications for National Demonstration projects will not be accepted during this funding cycle.

Authority for this program is contained in section 417B of the Higher Education Act of 1965, as amended.

(20 U.S.C. 1070d-1)

This program issues awards to institutions of higher education, combinations of institutions of higher education, public and private agencies and organizations, and, in exceptional cases, secondary schools and secondary vocational schools.

The purpose of the awards is to assist applicants to carry out projects designed to identify qualified youths of financial or cultural need with an exceptional potential for postsecondary educational training and encourage them to complete secondary school and undertake postsecondary educational training. Projects also publicize existing forms of student financial aid and encourage qualified secondary school and college dropouts of demonstrated aptitude to reenter educational programs.

Closing date for transmittal of applications: Applications for new awards must be mailed or hand delivered by October 31, 1979.

Applications delivered by mail: An application sent by mail must be addressed to the U.S. Office of Education, Application Control Center, Attention: 13.488, Washington, D.C. 20202.

Proof of mailing must consist of: (1) Legible U.S. Postal Service dated postmark;

(2) Legible mail receipt with the date of mailing stamped by the U.S. Postal Service; or

(3) Any other evidence acceptable to the Commissioner, such as dated shipping label, invoice, or receipt from a commercial carrier.

Private metered postmarks or mail receipts will not be accepted without a legible date stamped by the U.S. Postal Service. (Note.—The U.S. Postal Service does not uniformly provide a dated postmark. Applicants should check with their local post office before relying on this.) Applicants are encouraged to use registered or at least first class mail.

Each late applicant will be notified that its application will not be considered.

Applications delivered by hand: An application that is hand delivered must be taken to the U.S. Office of Education, Application Control Center, Room 5673, Regional Office Building 3, 7th and D Streets, S.W., Washington, D.C.

The Application Control Center will accept hand-delivered applications between 8:00 a.m. and 4:30 p.m. (Washington, D.C. time) daily, except Saturdays, Sundays, and Federal holidays.

Applications that are hand delivered will not be accepted after 4:30 p.m. on the closing date.

Program information: The applications for new grants will be evaluated competitively under the published funding criteria for new awards—45 CFR 159.7(c). All applications for FY 1980 funds will be treated as new applications. Successful applicants will receive up to two (2) year project period grants.

The Office of Education may not fund an applicant for a period of time longer than is requested by the applicant in the application. Applicants requesting two years of funding must submit a detailed work program and budget for the first year and an outline of the work program and a budget summary for the second year.

The Commissioner approves requests for the second year if: 1. The need continues to exist for the services provided by the project;

2. Satisfactory progress has been made in implementing the approved work plan and in achieving the project's goals and objectives;

3. The project continues to offer promise of success;

4. All required reports have been received and accepted by the Commissioner; and

5. Funds are available to continue the project.

An Application Preparation Workshop(s) will be conducted this Fall. For the time and location of this workshop(s) contact the Program Development Branch (see address in section on Further Information). Date(s) and location(s) will also be published in the Notices section of the Federal Register.

Available funds: Approximately $130,000,000 is anticipated to be available for the Special Programs for Students from Disadvantaged Backgrounds in FY 1980. The breakdown for new awards is estimated to be $51,000,000 for Upward Bound, with approximately 390 grants averaging $130,700; $15,300,000 for Talent Search, with approximately 160 grants averaging $95,600; and $45,000,000 for Special Services, with approximately 484 grants averaging $93,000. The Educational

Opportunity Centers program will be allocated $6,300,000 to fund approximately 27 grants averaging $233,000.

The processing of applications for new projects will be subject to the availability of funds. These estimates do not bind the U.S. Office of Education except as may be required by the applicable statute and regulations.

Application forms: Application forms and program information packages are expected to be ready for mailing by August 13, 1979. They may be obtained by writing to the Division of Student Services and Veterans Programs, Information Systems and Program Support Branch, U.S. Office of Education (Room 3514, Regional Office Building 3), 400 Maryland Avenue, S.W., Washington, D.C. 20202.

Applications must be prepared and submitted in accordance with the regulations, instructions, and forms included in the program information packages. The Commissioner suggests that the narrative portion of the application not exceed fifty (50) pages in length. The Commissioner further suggests that only the information required by the application form be submitted.

Applicable regulations: The regulations applicable to this program are:

(a) regulations governing the Talent Search Program (45 CFR Part 159), and

(b) Office of Educational General Provisions Regulations (45 CFR Parts 100 and 100a).

However, it is expected that the grant awards made under this program will be subject to the post award provisions of the Education Division General Administrative Regulations (EDGAR). EDGAR was published in proposed form in the Federal Register on May 4, 1979 (44 FR 26298). When published in final EDGAR will supersede the Office of Education General Provisions Regulations.

Further Information: For further information contact the Program Development Branch, Division of Student Services and Veterans Programs, U.S. Office of Education (Room 3514 Regional Office Building 3), 400 Maryland Avenue, SW., Washington, D.C. 20202, Telephone: (202) 245-2511.

(20 U.S.C. 1070d—1070d-1)

(Catalog of Federal Domestic Assistance Number 13.488; Talent Search)

Dated: July 17, 1979.

Mary Berry,

Acting Commissioner of Education.

[FR Doc. 79-22702 Filed 7-20-79; 8:45 am]

BILLING CODE 4110-02-M

Upward Bound; Closing Date for Transmittal of Applications for Fiscal Year 1980

Applications are invited for new projects under the Upward Bound Program. Applications for National Demonstration projects will not be accepted at this time. A separate Notice of Closing Date will be published at a later date.

Authority for this program is contained in section 417B of the Higher Education Act of 1965, as amended.

(20 U.S.C. 1070d-1)

This program issues awards to institutions of higher education, combinations of institutions of higher education, and public and private agencies and organizations, and in exceptional cases, to secondary schools and secondary vocational schools.

The purpose of the awards is to assist applicants to carry out projects designed to identify youths, from low-income backgrounds, with inadequate secondary school preparation, and to generate the skills and motivation necessary for eligible enrollees to complete secondary school and successfully pursue postsecondary educational programs.

Closing date for transmittal of applications: Applications for new awards must be mailed or hand delivered by October 12, 1979.

Applications delivered by mail: An application sent by mail must be addressed to the U.S. Office of Education, Application Control Center, Attention: 13.492, Washington, D.C. 20202.

Proof of mailing must consist of: (1) Legible U.S. Postal Service dated postmark;

(2) Legible mail receipt with the date of mailing stamped by the U.S. Postal Service; or

(3) Any other evidence acceptable to the Commissioner, such as dated shipping label, invoice, or receipt from a commercial carrier.

Private metered postmarks or mail receipts will not be accepted without a legible date stamped by the U.S. Postal Service. (Note.—The U.S. Postal Service does not uniformly provide a dated postmark. Applicants should check with their local post office before relying on this method.) Applicants are encouraged to use registered or at least first class mail.

Each late applicant will be notified that its application will not be considered.

Applications delivered by hand: An application that is hand delivered must be taken to the U.S. Office of Education, Application Control Center, Room 5673, Regional Office Building 3, 7th and D Street, S.W., Washington, D.C.

Application Control Center will accept hand-delivered applications between 8:00 a.m. and 4:30 p.m. (Washington, D.C., time) daily, except Saturdays, Sundays, and Federal holidays.

Applications that are hand delivered will not be accepted after 4:30 p.m. on the closing date.

Program information: The applications for new grants will be evaluated competitively under the published funding criteria for new awards—45 CFR 155.8(c). All applications for FY 1980 funds will be treated as new applications. Successful applicants will receive up to three (3) year project period grants.

Office of Education may not fund an applicant for a period of time longer than is requested by the applicant in the application. Applicants requesting more than one year of funding must submit a detailed work program and budget for the first year and an outline of the work program and a budget summary for each of the additional years.

The Commissioner approves requests for the subsequent years if: 1. The need continues to exist for the services provided by the project;

2. Satisfactory progress has been made in implementing the approved work plan and in achieving the project's goals and objectives;

3. The project continues to offer promise of success;

4. All required reports have been received and accepted by the Commissioner; and

5. Funds are available to continue the project.

An Application Preparation Workshop(s) will be conducted this Fall. For the time and location of this workshop(s) contact the Program Development Branch (see address in section of Further Information). Date(s) and location(s) will also be published in the Notices section of the Federal Register.

Available funds: Approximately $130,000,000 is anticipated to be available for the Special Programs for Students from Disadvantaged Backgrounds in FY 1980. The breakdown for new awards is estimated to be

$51,00,000 for Upward Bound, with approximately 390 grants averaging $137,000; $15,300,000 for Talent Search, with approximately 160 grants averaging $95,600; and $45,000,000 for Special Services, with approximately 484 grants averaging $93,000. The Educational Opportunity Centers program will be allocated $6,300,000 to fund approximately 27 grants averaging $233,000.

The processing of applications for new projects will be subject to the availability of funds. These estimates do not bind the U.S. Office of Education except as may be required by the applicable statute and regulations.

Application forms: Application forms and program information packages are expected to be ready for mailing by August 13, 1979. They may be obtained by writing to the Division of Student Services and Veterans Programs, Information Systems and Program Support Branch, U.S. Office of Education (Room 3514, Regional Office Building 3), 400 Maryland Avenue, S.W., Washington, D.C. 20202.

Applications must be prepared and submitted in accordance with the regulations, instructions, and forms included in the program information packages. The Commissioner suggests that the narrative portion of the application not exceed fifty (50) pages in length. The Commissioner further suggests that only the information required by the application form be submitted.

Applicable regulations: The regulations applicable to this program are: (a) regulations governing the Upward Bound Program (45 CFR Part 155); and

(b) Office of Education General Provisions Regulations (45 CFR 100 and 100a).

However, it is expected that the grant awards made under this program will be subject to the post award provisions of the Education Division General Administrative Regulations (EDGAR). EDGAR was published in proposed form in the Federal Register on May 4, 1979 (44 FR 26298). When published in final, EDGAR will supersede the Office of Education General Provisions Regulations.

Further information: For further information contact the Program Development Branch, Division of Student Services and Veterans Programs, U.S. Office of Education (Room 3514, Regional Office Building 3), 400 Maryland Avenue, S.W., Washington, D.C. 20202, Telephone: (202) 245-2511.

(20 U.S.C. 1070d-1070d-1.)

(Catalog of Federal Domestic Assistance Number 13.492; Upward Bound)

Dated: July 17, 1979.

Mary Berry,

Acting Commissioner of Education.

[FR Doc. 79-22704 Filed 7-20-79; 8:45 am]

BILLING CODE 4110-02-M

Health Care Financing Administration

Medicare Program; Schedule of Limits on Hospital Inpatient General Routine Operating Costs for Cost Reporting Periods Beginning on or After July 1, 1979

Correction

In FR Doc. 79-16780 appearing at page 31806 and the second of three documents in Part II of the issue for June 1, 1979, make the following corrections:

(1) On page 31808, in the first column, in the third full paragraph, in the 10th line, "related" should be corrected to read "relate".

(2) On page 31809, in the table entitled, Derivation of "Market Basket" Index for Routine Inpatient Hospital Operating Costs, in the first column entitled, Category of costs, under item No. 6, "U.S. Dept. of Commerce, Bureau of Economic" should be transferred to the fourth column of the table entitled, "Price" variable used. In the fourth column, under item No. 6, under entry A., insert "Source: U.S. Dept. of Commerce, Bureau of Economic" in front of "Analysis, *Survey of Current Business,* (monthly) table 26 (7.11)."

(3) On page 31810, in the third column, in the seventh full paragraph, in the 4th line, the two words "a typical" should be combined to make one word to read, "atypical".

(4) On page 31811, in the first column, in the second full paragraph, in the 17th line, "made" should be corrected to read, "make".

(5) On page 31813, in the first column, under Table III A—*Wage index for urban areas,* under the entry for Muncie, IN, the corresponding wage index should be "7878266".

(6) On page 31813, in the first column, under Table III A—*Wage index for urban areas,* under the entry for Raleigh-Durham, NC, the corresponding wage index should be "9982759".

(7) On page 31813, in the middle column, under Table III A—*Wage index for urban areas,* under the entry for "Wilmington, NC, the corresponding wage index should be "6793208".

BILLING CODE 1505-01-M

Medicare Program; Initial Schedule of Limits on Home Health Agency Costs Per Visit for Cost Reporting Periods Beginning on or After July 1, 1979

Correction

In FR Doc. 79-16781 appearing at page 31814 and the third of three documents in Part II of the issue for June 1, 1979, make the following corrections:

(1) On page 31814, in the third column, in the third full paragraph, in the 2nd line, "in" should be corrected to read "on".

(2) On page 31815, in the middle column, in the second full paragraph, in the 6th line, substitute the words "a written" for "writted".

(3) On page 31816, in the first column, in the 16th line from the top of the page, between the word "years" and the word "subtracting" delete the 2nd repeating word "and".

BILLING CODE 1505-01-M

Health Resources Administration

Advisory Committee; Meeting

In accordance with section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92-463), announcement is made of the following National Advisory body scheduled to meet during the month of August 1979:

Name: National Advisory Council on Health Professions Education.

Date and Time: August 13-14, 1979, 8:30 a.m.

Place: Conference Room 7-32, Center Building, 3700 East-West Highway, Hyattsville, Maryland 20782.

Open August 13, 1979, 8:30 a.m.-12:30 p.m. (10:30 a.m.-12:30 p.m. will be structured study for Council members.) Closed remainder of meeting.

Purpose: The Council advises the Secretary concerning the programs authorized by the Health Professions Educational Assistance Act of 1976, including recommendations on contacts, grant applications for construction, capitation, special projects, and financial need. These and other programs are designed to enable the health professions education institutions to meet the Nation's health manpower requirements.

Agenda: Agenda items for the open portion of the meeting will include Bureau Update, Update on 1979 Budget, consideration of minutes of previous meeting, and discussion of future meeting dates. The remainder of the meeting will be closed to the public for the review of applications for Curriculum Development in Applied Nutrition, Environmental Health and Geriatrics; and Capitation Assurances. The closing is in accordance with the provisions set forth in section 552b(c)(6), Title 5 U.S. Code, and the Determination by the Administrator, Health Resources Administration, pursuant to Pub. L. 92-463.

Anyone wishing to obtain a roster of members, minutes of meetings, or other relevant information should contact Mr. Robert L. Belsley, Bureau of Health Manpower, room 4-27, Center Building, 3700 East-West Highway, Hyattsville, Maryland 20782, Telephone (301) 436-6564.

Agenda items are subject to change as priorities dictate.

James A. Walsh,

Associate Administrator for Operations and Management.

[FR Doc. 79-22591 Filed 7-20-79; 8:45 am]

BILLING CODE 4110-83-M

Office of Human Development Service

Developmental Disabilities Program; Intention to Reallot Funds

AGENCY: Office of Human Development Services, HEW.

ACTION: Notice of Intention to Reallot Funds.

SUMMARY: The Developmental Disabilities Service and Facilities Construction Act, amended by Pub. L. 95-602, authorizes the Rehabilitation Services Administration (RSA) to reallot the amount of a State's fiscal year allotment for the Developmental Disabilities Program that it will not need. A reallotment can be made to other States in proportion to their original allotment in the same fiscal year. The proportionate amount realloted to a State can not be more than the amount that RSA estimates it will need and be able to use in the fiscal year. If the proportionate amount to a State is reduced for this reason, the total amount of all reductions made can be realloted to States whose proportionate share was not reduced. RSA is required to publish a notice of proposed reallotments in the Federal Register with a 30 day comment period.

COMMENTS: Consideration will be given to any written comments received on or before August 22, 1979. They should be submitted to: Director, Bureau of Developmental Disabilities, RSA, HDS, HEW, Room 3070, 330 C Street, SW., Washington, D.C. 20201.

Notice: The following allotments reserved in Fiscal Year 1979 for American Samoa, the Norther Mariana Islands, and the Trust Territory of the Pacific, will not be needed:

Basic support	Protection and advocacy
$150,000	$60,000

It is the intention of the Rehabilitation Service Administration to reallot the above as follows:

* * * * *

State	Basic support
Alabama	$3,579
Arizona	1,540
Arkansas	2,003
California	12,728
Colorado	1,567
Connecticut	1,930
Delaware	837
Dist. of Col.	837
Florida	5,618
Georgia	3,981
Guam	279
Hawaii	837
Illinois	7,237
Indiana	4,109
Iowa	2,371
Kansas	1,670
Kentucky	3,365
Louisiana	3,379
Maine	995
Maryland	2,627
Massachusetts	4,002
Michigan	6,547
Minnesota	3,026
Mississippi	2,457
Missouri	3,777
Montana	837
Nebraska	1,247
New Hampshire	837
New Jersey	4,599
New Mexico	956
New York	11,827
North Carolina	4,885
North Dakota	837
Oklahoma	2,288
Pennsylvania	9,355
Puerto Rico	4,018
Rhode Island	837
South Dakota	837
Tennessee	3,788
Texas	8,983
Utah	961
Vermont	837
Virginia	3,819
Virgin Islands	279
West Virginia	2,114
Wisconsin	3,724
Wyoming	837

State	Protection and advocacy
Alaska	$464
Arizona	618
Arkansas	778
California	5,061
Colorado	640
Connecticut	773
Delaware	464
Dist. of Col.	464
Florida	2,261
Hawaii	464
Idaho	464
Indiana	1,579
Iowa	848
Kansas	637
Kentucky	1,301
Louisiana	1,349
Maine	464
Maryland	1,016
Massachusetts	1,590
Michigan	2,523
Minnesota	1,131
Mississippi	973
Missouri	1,473
Montana	464
Nebraska	465
Nevada	464
New Hampshire	464
New Jersey	1,816
New Mexico	464
New York	4,821
North Dakota	464
Ohio	3,104
Oklahoma	805
Oregon	643
Pennsylvania	3,565
Puerto Rico	1,605
Rhode Island	464
South Carolina	1,027
South Dakota	464
Tennessee	1,482
Texas	3,571
Utah	464
Vermont	464
Virginia	1,407
Virgin Islands	464
Washington	928
West Virginia	781
Wisconsin	1,401
Wyoming	464

(Catalog of Federal Domestic Assistance Program No. 13.630 Development Disabilities—Basic Support)

Dated: July 10, 1979.

Robert R. Humphreys,

Commissioner, Rehabilitation Services Administration.

Arabella Martinez,

Approved: July 11, 1979.

Assistant Secretary for Human Development Services.

[FR Doc. 79-22683 Filed 7-20-79; 8:45 am]

BILLING CODE 4110-92-M

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

Bois Forte Band of Chippewa; Plan for the Use and Distribution of Bois Forte Band of Chippewa Judgment Funds Awarded in Docket 18-D Before the Indian Claims Commission

July 13, 1979.

This notice is published in exercise of authority delegated by the Secretary of the Interior to the Assistant Secretary for Indian Affairs by 209 DM 8.

The Act of October 19, 1973 (P.L. 93-134, 87 Stat. 466), requires that a plan be prepared and submitted to Congress for the use or distribution of funds appropriated to pay a judgment to any Indian tribe. Funds were appropriated by the Act of March 7, 1978, 92 Stat. 107, in satisfaction of the award granted to the Bois Forte Band of Chippewa Indians in Indian Claims Commission Docket 18-D. The plan for the use and distribution of the funds was submitted to the Congress with a letter dated February 9, 1979, and was received (as recorded in the Congressional Record) by the House of Representatives on Februry 13, 1979 and the Senate on March 15, 1979. Congress not having adopted a resolution disapproving it, the plan became effective on June 5, 1979, as provided by Section 5 of the 1973 Act, *supra.*

The plan reads as follows:

"The funds appropriated by the Act of March 7, 1978, 92 Stat. 107, in satisfaction of the award granted to the Bois Forte Band of Chippewa Indians in Docket 18-D before the Indian Claims Commission, less attorney fees and expenses, and including all interest and investment income accrued, shall be utilized as herein provided.

Per Capita Aspect

The Secretary of the Interior (hereinafter 'Secretary') shall make a per capita distribution, in a sum as equal as possible, of eighty (80) percent of the funds, to each enrollee of the Minnesota Chippewa Tribe, pursuant to the provisions of the revised tribal constitution approved March 3, 1964, as amended, who is designated as a Lake Superior Chippewa Band member and who is affiliated with the Nett Lake (Bois Forte) Reservation, including Vermillion Lake and Deer Creek Reservations, and who was born on or prior to and living on the effective date of this plan. The Lake Superior Chippewa Band roll of the Minnesota Chippewa Tribe, for the purpose of determining the number of enrollees affiliated with the Nett Lake (Bois Forte) Reservation, including Vermillion Lake and Deer Creek Reservations, shall be brought current under procedures enacted by the tribe and approved by the Secretary.

Programming Aspect

The balance, or twenty (20) percent of the funds, shall be deposited in separate program accounts in the percentages set forth herein and such funds shall be invested by the Secretary pursuant to 25 USC 162a, until such time the funds are required for the programs. The interest and investment earnings on each account shall first be utilized in the programs, which are to be detailed in separate program plans and tribal budgets of the Nett Lake (Bois Forte) Reservation Business Committee and approved by the Secretary, with the principal funds of each account maintained intact wherever possible.

a. Twenty-five (25) percent of the program funds, and interest and investment income accruing thereon, shall be utilized in an annual educational scholarship program.

b. Forty (40) percent of the program funds, and interest and investment income accruing thereon, shall be utilized in a reservation economic development program, for such purposes as matching funds for Federal programs, assistance to individual tribal members establishing on-reservation businesses, assistance to individual tribal members seeking Small Business Administration loans, etc.

c. Thirty-five (35) percent of the program funds and interest and investment income accruing thereon, shall be utilized in a band land acquisition program.

General Provisions

No person shall be entitled to more than one per capita share of the funds.

The per capita shares of living competent adults shall be paid directly to them. The per capita shares of minors shall be handled pursuant to 25 CFR 60.10 (a) and (b)(1) and 104.4. The per capita shares of legal incompetents shall be place in individual Indian money (IIM) accounts and handled under 25 CFR 104.5. The per capita shares of deceased individual beneficiaries shall be determined and distributed in accordance with 43 CFR, Part 4, Subpart D.

Should funds set aside in any of the program accounts be determined to be in excess of needs, appropriate adjustments from one program account to another shall be made in the annual tribal budget, with the approval of the Secretary.

None of the funds distributed per capita or made available under the programming aspects of this plan shall be subject to Federal or State income taxes or be considered income or resources in determining eligibility for assistance under Federal, State or local programs."

Rick Lavis,

Deputy Assistant Secretary—Indian Affairs.

[FR Doc. 79-22593 Filed 7-20-79; 8:45 am]

BILLING CODE 4310-02-M

Lummi Indian Reservation, Washington; Ordinance Regulating the Use, Consumption, Sale, or Possession of Intoxicating Beverages

July 9, 1979.

This Notice is published in accordance with authority delegated by the Secretary of the Interior to the Assistant Secretary—Indian Affairs by 209 DM 8, and in accordance with the Act of August 15, 1953, Public Law 277, 83rd Congress, 1st Session, (67 Stat. 586). I certify that the following Resolution and Ordinance relating to the application of the Federal Indian Liquor Laws on the Lummi Indian Reservation, Washington was adopted on October 6, 1978 and amended on February 6, 1979 and on June 4, 1979 by the Lummi Indian Business Council which has jurisdiction over the area of Indian Country included in the Resolution and Ordinance, reading as follows:

Rick Lavis,

Deputy Assistant Secretary—Indian Affairs.

Resolution No. 78-85 of the Lummi Indian Business Council

Whereas, the Lummi Indian Business Council is the duly constituted governing body of the Lummi Indian Reservation by the authority of the Constitution and By-Laws of the Lummi Tribe of the Lummi Reservation, Washington, as approved on April 10, 1970, by the Assistant Commissioner of Indian Affairs; and

Whereas, the Lummi Indian Business Council has the duty and responsibility of regulating the possession, use, consumption, and sale of alcoholic beverages on the Lummi Indian Reservation;

Now, therefore, be it resolved that the Lummi Indian Business Council does adopt the attached Liquor Code; and

Be it further resolved that the Chairman (or the Vice Chairman in his absence) is authorized and directed to execute this resolution and any documents connected herewith; and the Secretary is authorized and directed to execute the following certification.

Lummi Indian Tribe.

William E. Jones,

Chairman, Lummi Indian Business Council.

Certification

As Secretary of the Lummi Indian Business Council, I hereby certify that the above resolution No. 78-85 was adopted at a regular meeting of the Council held on the 6th day of October, 1978, at which time a quorum of 6 was present and was adopted by a vote of 5 for, 0 against, and 0 abstentions.

James H. Wilson,

Secretary Lummi Indian Business Council.

Liquor Code

Section 1. Findings and Purpose.

1.1 The introduction, possession, and sale of liquor on Indian reservations have, since Treaty time, been clearly recognized as matters of special concern of Indian tribes and the United States Federal Government. The control of liquor on reservations remains exclusively subject to their legislative enactments.

1.2 Beginning with the Treaty of Point Elliott, Art. X, to which the ancestors of the Lummi Indian Tribe were parties, the Federal Government has respected this Tribe's determinations regarding liquor related transactions and activities on the Lummi Indian Reservation. At Treaty time, the

Lummi Tribe's ancestors desired to exclude "ardent spirits" from their Reservation. This desire was honored by Congress in the enactment of 18 U.S.C. § 1154 and 18 U.S.C. § 1161, which prohibit the introduction of liquor into the Lummi Indian Reservation unless and until the Lummi Indian Tribe has decided when and to what extent liquor transactions shall be permitted. The Lummi Tribe has decided to open the Lummi Indian Reservation to the possession, consumption, and sale of liquor by enacting Resolution L-33 on March 14, 1972. Subsequent circumstances have made it clear that it is now necessary for the Lummi Indian Tribe to exert strict tribal regulation and control over all aspects of liquor sale, distribution, and use of the Lummi Indian Reservation.

1.3 The enactment of the tribal ordinance governing liquor sales on the Lummi Indian Reservation and providing for exclusive purchase and sale through a tribally owned and operated establishment will increase the ability of the Tribal Government to control Reservation liquor distribution and possession, and, at the same time, will provide an important source of revenue for the continued operation of essential tribal governmental services and the delivery of essential tribal social services.

1.4 Tribal regulation of the sale, possession, and consumption of liquor on the Lummi Indian Reservation is necessary to protect the health, security, and general welfare of the Lummi Indian Tribe. In order to further these goals and to provide for an urgently needed additional source of governmental revenue, the Lummi Indian Business Council adopts this liquor ordinance to be known as the "Lummi Liquor Ordinance". This ordinance shall be liberally construed to fulfill the purposes for which it has been adopted.

Section 2. Definitions. As used in this ordinance, the following words shall have the following meanings unless the context clearly requires otherwise.

2.1 "Alcohol" That substance known as ethyl alcohol, hydrated oxide of ethyl, or spirit of wine, which is commonly produced by the fermentation or distillation of grain, starch, molasses, or sugar, or other substances including all dilutions and mixtures of this substance.

2.2 "Alcoholic Beverage" Is synonymous with the term liquor as defined in § 2.5 of this ordinance.

2.3 "Beer" Means any beverage obtained by the alcoholic fermentation of an infusion or decoction of pure hops, or pure extract of hops and pure barley malt or other wholesome grain or cereal in pure water containing not more than four percent of alcohol by volume. For the purposes of this title, any such beverage, including ale, stout, and porter, containing more than four percent of alcohol by weight shall be referred to as "strong beer".

2.4 "Board" Means the Lummi Indian Liquor Board as constituted under this ordinance.

2.5 "Liquor" includes the four varieties of liquor herein defined (alcohol, spirits, wine, and beer), and all fermented, spirituous, vinous, or malt liquor or combinations thereof, and mixed liquor, a part of which is fermented, spirituous, vinous, or malt liquor, or otherwise intoxicating; and every liquid or solid or semi-solid or other substance, patented or not, containing alcohol, spirits, wine or beer, and all drinks or drinkable liquids and all preparations or mixtures capable of human consumption and any liquid, semi-solid, solid, or other substances, which contains more than one percent of alcohol by weight shall be conclusively deemed to be intoxicating.

2.6 "Malt Liquor" Means beer, strong beer, ale, stout, and porter.

2.7 "Package" Means any container or receptacle used for holding liquor.

2.8 "Public Place" Includes streets and alleys of incorporated cities and towns; state or county or tribal or federal highways or roads; buildings and grounds used for school purposes; public dance halls and grounds adjacent thereto; those parts of establishments where beer may not be sold under this title, soft drink establishments, public buildings, public meeting halls, lobbies, halls, and dining rooms of hotels, restaurants, theaters, stores, garages, and filling stations which are open to and are generally used by the public and to which the public is permitted to have unrestricted access; railroad trains, stages, and other public conveyances of all kinds and character, and the depots and waiting rooms used in conjunction therewith which are open to unrestricted use and access by the public; publicly owned bathing beaches, parks, and/or playgrounds, and all other places or like or similar nature to which the general public has unrestricted right of access, and which are generally used by the public.

2.9 "Sale" and "Sell" Include exchange, barter, and traffic; and also include the selling or supplying or distributing, by any means whatsoever, or liquor, or of any liquid known or described as beer or by any name whatsoever commonly used to describe malt or brewed liquor or of wine, by any person to any person.

2.10 "Spirits" Means any beverage which contains alcohol obtained by distillation, including wines exceeding seventeen percent of alcohol by weight.

2.11 "Tavern" Means any establishment with special space and accommodations for sale by the glass and for consumption on the premises, of beer, as herein defined.

2.12 "Wine" Means any alcoholic beverage obtained by fermentation of fruits (grapes, berries, apples, etc.) or other agricultural product containing sugar, to which any saccharine substances may have been added before, during, or after fermentation, and containing not more than seventeen percent of alcohol by weight, including sweet wines fortified with wine spirits, such as port, sherry, muscatel, and angelica, not exceeding seventeen percent of alcohol by weight.

Section 3. Lummi Indian Liquor Board

3.1 *Liquor Board Established—Composition.* There is hereby established a Lummi Indian Liquor Board. The Board shall consist of five (5) members serving staggered terms of three (3) years, each, commencing on March 1st of each year, and selected by vote of the Lummi Indian Business Council as follows:

(1) three (3) members shall be members of the Lummi Indian Business Council who reside on the Lummi Indian Reservation.

(2) two (2) members shall be members of the Lummi Indian Tribe, residing upon the Lummi Indian Reservation, who are not members of the Lummi Indian Business Council at the time of their selection; Provided, however, that no position on the Board shall become vacant by virtue of the individual holding that position failing to be re-elected to the Lummi Indian Business Council unless that individual shall specifically resign from the Board. No person shall serve on the Board who has ever been convicted of a felony or misdemeanor involving dishonesty.

3.2 *Vacancies.* All vacancies occurring on the Board shall be filled by a vote of the Lummi Indian Business Council.

3.3 *Initial Board.* The initial terms of office of the Board shall be as follows:

(1) one (1) member shall serve a three-year (3) term;

(2) two (2) members shall serve two-year (2) terms;

(3) two (2) members shall serve one-year (1) terms.

The members serving respective terms shall be determined by lot after the members have been selected by the Lummi Indian Business Council.

3.4 *Board Compensation.* The members of the board shall serve without compensation unless otherwise directed by the Lummi Indian Business Council, but may receive reimbursement for necessary expenses and mileage actually incurred in the performance of their duties.

3.5 *Removal.* Members of the Board shall serve in good behavior and shall be subject to removal only by the Lummi Indian Business Council and only after a full hearing at which the member shall be afforded the right to notice of the specific charges against him, to present evidence in his own behalf, and to cross-examine witnesses against him. The member may be represented by counsel or a spokesman admitted to the Lummi Tribal Court, but such representation shall not be paid for out of funds under the control of the Board. If the Board member who is the subject of the hearing is also a member of the Lummi Indian Business Council, he shall be disqualified from voting as a member of the Lummi Indian Business Couincil at the hearing. Removal shall be by simple majority of the eleven members of the Council. Grounds for removal shall include, but not be limited to,

(1) conviction of a felony or a crime involving dishonesty;

(2) misuse of Board funds;

(3) receiving improper gratuities or payments from liquor salesmen or wholesalers;

(4) gross neglect of duty;

(5) failure to comply with a proper directive of the Lummi Indian Business Council

3.6 *Board Reports to Lummi Indian Business Council.* The Board shall prepare an annual written report on its activities to be submitted to the Lummi Indian Business Council at the March meeting of the Lummi Indian Business Council. The report shall include an accounting of all receipts and expenditures and such other information as shall seem appropriate to The Board or as shall be directed by the Lummi Indian Business Council. The Board may submit such other further reports as it deems appropriate or as the Lummi Indian Business Council shall direct.

3.7 *Board—Powers and Duties.* The Board shall have the following powers and duties:

(1) to publish and enforce rules and regulations adopted by the Lummi Indian Business Council governing the sale, manufacture, and distribution of alcoholic beverages on the Lummi Indian Reservation;

(2) to employ managers, warehousemen, accountants, security personnel, drivers, and such other persons as shall be reasonably necessary to allow the Board to perform its functions. Such employees shall be hired through the Lummi Indian Tribal Personnel office, and, although paid by and responsible to, the Board, shall be considered tribal employees for all other purposes;

(3) to lease or construct appropriate warehouse facilities;

(4) to bring suit in the appropriate court with the consent of the Lummi Indian Business Council. The Board shall not, without the specific consent of the Lummi Indian Business Council, waive the Board's or the Lummi Indian Tribe's immunity from suit;

(5) to contract with liquor wholesalers and distributors for the purchase and delivery of alcoholic beverages;

(6) to make such reports as may be required by the Lummi Indian Business Council;

(7) to take orders, receive, and distribute shipments of alcoholic beverages, establish wholesale base prices, collect taxes and fees levied or set by the Lummi Indian Business Council, and to keep accurate records, books, and accounts;

(8) to exercise such other powers as are delegated by the Lummi Indian Business Council.

3.8 *Board-Prohibited Actions.* In the exercise of its powers and duties, neither the Board nor any of its members shall:

(1) accept any gratuity, compensation or other thing of value from any liquor wholesaler or distributor or from any licensee, applicant, or prospective applicant, except as he is duly established for licensing;

(2) waive the immunity of the Board or the Lummi Indian Tribe from suit without the express consent of the Lummi Indian Business Council.

3.9 *Warehouse.* The Board shall purchase, lease, or construct an appropriate secure warehouse located on the Lummi Indian Reservation for the receipt, storage, and distribution of alcoholic beverages.

3.10 *Inspection.* The premises of the Board shall be open by its employees for inspection by the Board, or by any member of the Lummi Indian Business Council directed by the Lummi Indian Business Council to so inspect, at all reasonable times for the purposes of ascertaining whether the rules and regulations of the Board and the liquor laws of the Lummi Indian Reservation are being complied with.

Section 4. Sales.

4.1 *Only Tribal Sales Allowed.* No sales of alcoholic beverages shall be made within the exterior boundaries of the Lummi Indian Reservation, except at a tribal liquor store.

4.2 *All Sales Cash.* All sales at tribal liquor stores shall be on a cash only basis and no credit shall be extended to any person, organization, or entity.

4.3 *All Sales For Personal Use.* All sales shall be for the personal use of the purchaser, and resale for profit of any alcoholic beverage purchased at a tribal liquor store is prohibited within the Lummi Indian Reservation. Any person who purchases an alcoholic beverage at a tribal store and resells that beverage for profit, whether in the original container or not, shall be quilty of an offense and punished in accordance with § 6.15 herein.

4.4 *Tribal Property.* The entire stock of liquor and alcoholic beverages referred to under this ordinance shall remain tribal property owned and possessed by the Lummi Indian Tribe until sold.

Section 5. Taxation.

5.1 *Tax Imposed.* There is hereby levied and shall be collected a tax on each retail sale of alcoholic beverages on the Reservation in the amount of 15% of the retail sales price. The tax imposed by this section shall apply to all retail sales of liquor on the Reservation and shall pre-empt any tax imposed on such liquor sales by the State of Washington. No municipality, city, town, county, nor the State of Washington shall have any power to impose an excise tax on liquor or alcoholic beverages as defined by this title, or to govern or license the sale or distribution thereof in any manner within the Lummi Indian Reservation.

5.2 *Distribution of Taxes.* All taxes from the sale of alcoholic beverages on the Lummi Indian Reservation by or through the Board shall be paid over to the General Treasury of the Lummi Indian Tribe and be subject to the distribution by the Lummi Indian Business Council in accordance with its usual appropriation procedures for essential governmental and social services; Provided, however, that the following tribal programs shall have priority in funding in the percentages set out in this section upon demonstration of need and past performances in the normal tribal budgetary appropriation process:

(1) to the Lummi Tribal Alcohol Program in an amount of at least 15% of the total tax received;

(2) to the Lummi Tribal Elders Program in an amount of 15% of the total tax received;

(3) to the Lummi Tribal Youth Program in an amount of at least 15% of the total tax received;

(4) to the Lummi Tribal Law and Order Program in an amount of at least 15% of the total tax received;

(5) to the Lummi Tribal Education Program in an amount of at least 15% of the total tax received;

(6) to other tribal needs as designated by the Lummi Indian Business Council.

Section 6. Illegal Activities.

6.1 *Liquor Stamp—Contraband.* No Alcoholic beverages shall be sold on the Lummi Indian Reservation unless there shall be affixed to the package a stamp of the Board. Any sales made in violation of this provision shall be a violation of this ordinance and shall be punishable as set out in § 6.15 herein. All alcoholic beverages not so stamped which are sold or held for sale on the Lummi Indian Reservation are hereby declared contraband and, in addition to any penalties imposed by the Court for violation of this section, it shall be confiscated and forfeited in accordance with the procedures set out in Title 14 of the Lummi Code of Laws.

6.2 *Proof of Unlawful Sale—Intent.* In any proceeding under this ordinance, proof of one unlawful sale of liquor shall suffice to establish *prima facie* the intent or purpose of unlawfully keeping liquor for sale in violation of this ordinance.

6.3 *Use of Seal.* No person other than an employee of the Board shall keep or have in his possession any legal seal prescribed under this ordinance unless the same is attached to a package which has been purchased from a tribal liquor store, nor shall any person keep or have in his possession any design in imitation of any official seal prescribed under this ordinance or calculated to deceive by its resemblance to any official seal, or any paper upon which such design is stamped, engraved, lithographed, printed or otherwise marked. Any person who willfully violateds any provision of this section shall be guilty of an offense.

6.4 *Illegal Sale of Liquor by Drink or Bottle.* Except as otherwise provided in this ordinance, any person who sells by the drink or bottle any liquor, shall be guilty of an offense.

6.5 *Illegal Transportation, Still, or Sale Without Permit.* Any person who shall sell or offer for sale or transport in any manner, any liquor in violation of this ordinance, or who shall operate or shall have in his possession without a permit, any mash capable of being distilled into liquor, shall be quility of an offense.

6.6 *Illegal Purchase of Liquor.* Any person within the boundaries of the Lummi Indian Reservation who buys liquor from any person other than at a property authorized tribal liquor store shall be guilty of an offense.

6.7 *Illegal Possession of Liquor—Intent to Sell.* Any person who keeps or possesses liquor upon his person or in any place or on premises conducted or maintained by him as a principal or agent with the intent to sell it contrary to the provisions of this ordinance, shall be quilty of an offense.

6.8 *Sales to Persons Apparently Intoxicated.* Any person who sells liquor to a person apparently under the influence of liquor shall be guilty of an offense.

6.9 *Drinking In a Public Conveyance.* Any person engaged wholly or in part in the business of carrying passengers for hire, and every agent, servant, or employee of such person who shall knowingly permit any person to drink any liquor in any public conveyance shall be guilty of an offense. Any person who shall drink any liquor in a public conveyance shall be guilty of an offense.

6.10 *Furnishing Liquor to Minors.* Except in the case of liquor given or permitted to be given to a person under the age of twenty one (21) years by his parent or guardian, for beverage or medicinal purposes, or administered to him by his physician or dentist for medicinal purposes, no person under the age of tweny one (21) years shall consume, acquire, or have in his possession any alcoholic beverages except when such beverage is being used in connection with religious services. No person shall permit any other person under the age of twenty one (21) to consume liquor on his premises or on any premises under his control except in those situations set out in this section. Any person violating this section shall be guilty of an offense.

6.11 *Sales of Liquor to Minors.* Any person who shall sell any liquor to any person under the age of twenty one (21) years shall be guilty of an offense.

6.12 *Unlaw Transfer of Identification.* Any person who transfer in any manner an identification of age to a minor for the purpose of permitting such minor to obtain liquor shall be quilty of an offense; Provided, that corroborative testimony of a witness other than the minor shall be a requirement of conviction.

6.13 [Reserved]

6.14 *Possession of False or Altered Identification.* Any person who attempts to purchase an alcoholic beverage through the use of false or altered identification which falsely purports to show the individual to be over the age of 21 years shall be quilty of an offense.

6.15 *General Penalties.* Any Indian person guilty of a violation of this ordiance for which no penalty has been specifically provided shall be liable upon conviction for imprisonment for a period of not to exceed six (6) months, or a fine of not exceed Five Hundred Dollars ($500.00), or both such fine and imprisonment.

6.16 *Identification—Proof of Minimum Age.* Where there may be a question of a person's right to purchase liquor by reason of his age, such person shall be required to present any one of the following officially issued cards of identification which shows correct age and bears his signature and photograph:

(1) liquor control authority card of identification of any state.

(2) driver's license of any state or "Identi-Card" issued by any State Department of Motor Vehicles.

(3) United States Active Duty Military Identification.

(4) Passport.

(5) Lummi Tribal Identification or Enrollment card.

6.17 *Illegal Items Declared Contraband.* Alcoholic beverages which are possessed contrary to the terms of this section are declared to be contraband. Any officer who shall make an arrest under this section shall seize all contraband which he shall have the authority to seize consistent with the Lummi Constitution and the applicable provisions of 25 U.S.C. § 1302.

6.18 *Preservation and Forfeiture.* Any officer seizing contraband shall preserve the contraband in accordance with the provisions established for the preservation of impounded property in Title 14 of this Code. Upon conviction, the guilty party shall forfeit all right, title and interest in the items seized and when the conviction shall become final, the items shall be disposed of as provided for in Title 14 of this Code; Provided, however, that the items so forfeited shall not be sold to any person not entitled to possess them under applicable law.

Section 7. Abatement.

7.1 *Declaration of Nuisance.* Any room, house, building, boat, vessel, vehicle, structure, or other place where liquor is sold, manufactured, bartered, exchanged, given away, furnished, or otherwise disposed of in violation of the provisions of this ordinance or of any other tribal law relating to the manufacture, importation, transportation, possession, distribution, and sale of liquor, and all property kept in and used in maintaining such place, are hereby declared to be a common nuisance.

7.2 *Institution of Action.* The Chairman of the Board shall institute and maintain an action in the Tribal Court in the name of the Tribe to abate and perpetually enjoin any nuisance declared under this title. The plaintiff should not be required to give bond in the action, and restraining orders, temporary injunctions, and permanent injunctions may be granted in the cause as in other injunction proceedings, and upon final judgment against the defendant, the Court may also order the room, house, building, boat, vessel, vehicle, structure, or place closed for a period of one (1) year or until the owner, lessee, tenant, or occupant thereof shall give bond of sufficient surety to be approved by the Court in the penal sum of not less than One Thousand Dollars ($1,000.00), payable to the Tribe and conditioned that liquor will not be thereafter manufactured, kept, sold, bartered, exchanged, given away, furnished, or otherwise disposed of thereof in violation of the provisions of this ordinance or of any other applicable tribal law, and that he will pay all fines, costs, and damages assessed against him for any violation of this ordinance or other tribal liquor laws. If any condition of the bond be violated, the whole amount may be recovered as a penalty for the use of the tribe. Any action taken under this section shall be in addition to any criminal penalties provided in this ordinance.

7.3 *Abatement.* In all cases where any person has been convicted of a violation of this ordinance or tribal laws relating to the manufacture, importation, transportation, possession, distribution, and sale of liquor, an action may be brought in Tribal Court to abate as a nuisance any real estate or other property involved in the commission of the offense, and in any such action a certified copy of the record of such conviction shall be admissable in evidence and *prima facie* evidence that the room, house, vessel, boat, building, vehicle, structure, or place against which such action is brought is a public nuisance.

Section 8. Profits

8.1 *Distribution of Profits.* The gross proceeds collected by the Board for all sales of alcoholic beverages on the Lummi Indian Reservation shall be distributed as follows:

(1) for the cost of goods;

(2) for the payment of taxes provided in § 5 of this ordinance;

(3) for the payment of all necessary personnel, administrative costs, and legal fees for the Board and its activities;

(4) the remainder shall be turned over to the General Fund of the Lummi Indian Tribe in quarterly payments and expended by the Lummi Indian Business Council.

8.2 *Expenditure of Profits.* All profits transferred to the tribal General Fund by the Board shall be expended by the Lummi Indian Business Council for the general governmental services of the Tribe.

Section 9. Severability and Effective Date.

9.1 If any provision or application of this ordinance is determined by review to be invalid, such adjudication shall not be held to render ineffectual the remaining portions of this ordinance or to render such provisions inapplicable to other persons or circumstances.

9.2 *Effective Date.* This ordinance shall be effective on such date as the Secretary of the Interior certifies this ordinance and publishes the same in the Federal Register.

9.3 *Inconsistent Enactments Rescinded.* Any and all prior enactments of the Lummi Indian Business Council which are inconsistent with the provisions of this ordinance are hereby rescinded.

9.4 *Disclaimer.* Nothing in this ordinance shall be construed to require or authorize the criminal trial and punishment by the Lummi Tribe Court of any non-Indian except to the extent allowed by any applicable present or future Act of Congress or any applicable decision of the United States Supreme Court.

9.5 *Application of 18 U.S.C. § 1161.* All acts and transactions under this ordinance shall be in conformity with this ordinance and in conformity with the laws of the State of Washington as that term is used in 18 U.S.C. § 1161.

[FR Doc. 79-22592 Filed 7-20-79; 8:45 am]

BILLING CODE 4310-02-M

Bureau of Land Management

[AA-6676-A, AA-6676-B, AA-6676-D through AA-6676-F, AA-6676-H, and AA-6676-J through AA-6676-L]

Alaska Native Claims Selections

Correction

In FR Doc. 79-20177, published at page 37986, on Friday, June 29, 1979, the following corrections are made:

1. On page 37986, in the third column, in the section "T. 5S., R. 47W.", in the fifth line "Anushagak River" should be changed to read "Nushagak River";
2. On page 37986, in the third column, at the bottom of the column, the last section "T. 4, R. 48 W" should be corrected to read "T. 4S, R. 48 W"
3. On page 37987, in the second column, in the last line of the column, "Nuyauk" should be corrected to read "Nuyakuk".

BILLING CODE 1505-01-M

[NM 37466, 37467, and 37475]

New Mexico; Notice of Applications

July 10, 1979.

Notice is hereby given that, pursuant to Section 28 of the Mineral Leasing Act of 1920 (30 U.S.C. 185), as amended by the Act of November 16, 1973 (87 Stat. 576), Southern Union Gathering Company has applied for two 2-inch and one 4-inch natural gas pipeline rights-of-way across the following lands:

New Mexico Principal Meridian, New Mexico

T. 32 N., R. 12 W.,
Sec. 24, NW¼SE¼;
Sec. 35, S½NE¼ and SW¼SW¼.

These pipelines will convey natural gas across 0.21 of a mile of public lands in San Juan County, New Mexico.

The purpose of this notice is to inform the public that the Bureau will be proceeding with consideration of whether the applications should be approved, and if so, under what terms and conditions.

Interested persons desiring to express their views should promptly send their name and address to the District Manager, Bureau of Land Management, P.O. Box 6770, Albuquerque, New Mexico 87107.

Fred E. Padilla,
Chief, Branch of Lands and Minerals Operations.

[FR Doc. 79-22682 Filed 7-20-79; 8:45 am]

BILLING CODE 4310-84-M

Office of the Secretary

Proposed 5-Year OCS Oil and Gas Leasing Program

AGENCY: Office of Outer Continental Shelf Program Coordination.

ACTION: Publication of Proposed 5-Year OCS Oil and Gas Leasing Program.

SUMMARY: Section 18 of the OCS Lands Act, as amended, requires the preparation of a proposed 5-year OCS Oil and Gas Leasing Program and its publication in the Federal Register. The leasing program is to consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing and location of leasing activity which the Secretary of the Interior determines will best meet national energy needs for the 5-year period following its approval. Pursuant to section 18(c)(3) of the Act, as amended, a proposed leasing program is to be submitted to the Congress, the Attorney General and the Governors of affected States, and published in the Federal Register. A proposed 5-year leasing program has been developed covering the period March 1980 through February 1985.

On June 18, 1979, the proposed program was submitted to the Congress. On June 25, 1979, the proposed program was submitted to the Governors of the affected coastal States, together with additional information and data used by Secretary Andrus in reaching his decision, and as required by section 18(c)(2) of the Act, it included responses to correspondence received from the Governors on the draft proposed program. On June 27, 1979, the correspondence between Secetary Andrus and the Governors, and the background material used by the Secretary in reaching his decision were transmitted to the Congress. On June 29, 1979, the proposed program and additional information and data were submitted to the Attorney General.

The June 18, 1979, letter to the Congress constitutes the Secretary of Interior's submittal of the proposed leasing program and appears in the Federal Register today. Single copies of the additional information and data submitted to Congress, the Governors of the affected coastal States and the Attorney General may be acquired by written request to: Director, Office of OCS Program Coordination, Department of the Interior, Room 5150, 18th and C Streets, NW., Washington, D.C. 20240.

DATE: Interested parties may submit written comments on the proposed program until September 21, 1979.

ADDRESSES: Send comments to: Director, Office of OCS Program Coordination, Department of the Interior, Room 5150, 18th & C Streets, NW., Washington, D.C. 20240.

FOR FURTHER INFORMATION CONTACT: Carolita Kallaur, Office of OCS Program Coordination, Department of the Interior, Room 5150, 18th & C Streets, NW., Washington, D.C. 20240, telephone 202/343-9314.

AUTHOR: Carolita Kallaur, Office of OCS Program Coordination, Department of the Interior, Room 5150, 18th & C Streets, NW., Washington, D.C. 20240, telephone 202/343-9314.

SUPPLEMENTARY INFORMATION: Comments received on the proposed leasing program will be considered by the Department of the Interior prior to the transmittal of the proposed final leasing program to Congress and the President. This transmittal will be in accordance with section 18(d)(2) of the OCS Lands Act, as amended.

An environmental impact statement (EIS) is also being prepared to consider the environmental effects of the program. The draft EIS is scheduled to be released on August 24, 1979, and the analysis included in the draft EIS will be considered in the preparation of the proposed final leasing program. The results of the final EIS, which is scheduled to be released in January 1980, will be considered in the Secretarial decision on the final program.

Dated: July 13, 1979.

Heather L. Ross,
Deputy Assistant Secretary—Policy, Budget and Administration.

United States Department of the Interior
Office of the Secretary
Washington, D.C. 20240
June 18, 1979
Honorable Walter F. Mondale,
President of the Senate,
Washington, D.C. 20510

Dear Mr. President: Section 18 of the OCS Lands Act, as amended, requires the preparation of a 5-year leasing program. According to the statute, I am to submit, by June 18, 1979, a proposed leasing program to the Congress, the Attorney General, and the Governors of the affected States. This letter constitutes my submission of the program.

Section 18(a) of the Act establishes the content of the leasing program. Specifically, it requires that the program consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which I determine will best meet national energy needs for the 5-year period following approval of the program. Section 18(b) adds the requirement that the program include certain estimates of appropriations and staff.

Attachment 1 is a schedule showing the location by area and timing of the sales in my proposed program which are planned for the period March 1980 through February 1985. The schedule also shows the pre-sale planning steps leading to a final decision on each of the proposed sales. While the 1979 column does not include the proposed sales which are scheduled for this year, they are proceeding on schedule: sale 48, southern California, June 1979; sale 58, Gulf of Mexico, July 1979; sale 42, North Atlantic, October 1979; sale 58A, Gulf of Mexico, November 1979; Federal/State joint sale in the Beaufort Sea, December 1979.

Attachment 2 contains two maps showing the general leasing areas where the sales on the proposed program will be considered. Attachment 3 is a listing of possible sale sizes. More precise descriptions of size and location of possible sales will be available when the planning for them gets underway.

Attachment 4 contains estimates of appropriations and staff for four specific activities as required by section 18(b). Because the four activities do not cover all the costs of the program, we have added a fifth activity covering the remaining costs so that you and others can see what the total costs are estimated to be over the 5-year period.

This letter and the four attachments mentioned above constitute my proposed leasing program as specified in the Act.

Section 18(c)(2) requires that when I submit my proposed program to the Congress, it be accompanied by copies of certain correspondence between the Governors of affected States and me. This correspondence is being completed and will be sent to you in a few days.

Section 18(a)(2) of the Act requires that in preparing the proposed program, I consider eight factors. When I send you the correspondence with the Governors, I will also send you a staff memorandum, and its attachments, discussing the required factors and other elements involved in my decision.

I have determined that the best way for the OCS leasing program to meet the energy needs of the nation is to adopt a schedule of proposed sales that provides for a mixture of lease sales among proven oil and gas producing areas and frontier areas. This coverage, coupled with my firm determination to proceed in a manner that protects the human, marine and coastal environments from undue risk and harm, has led me to propose a 5-year program with 30 sales plus a contingency sale. On a regional basis, the proposed schedule calls for six sales in the Atlantic, 11 in the Gulf of Mexico, four off California, and nine off Alaska. The Contingency sale is in the Gulf of Mexico. Subsequent events, such as the deletion of another sale, will determine whether the contingency sale will be held as indicated, held at some other time during the 5-year period, deleted, or postponed until after February 1985.

There are several important aspects of the proposed schedule which I would like to emphasize:

In developing the proposed schedule, I have considered the availability of environmental, geologic and other information important to making sale decisions. I would be the first to agree that there are differences among experts about the precise nature and timing of needed information. However, I am convinced that with the improvements we have made in the design of the environmental studies program, with our improved record of cooperation with affected coastal States, and with our improved management of offshore activities, we can start planning for the sales I am proposing with a high degree of confidence.

The proposed program is compatible with the OCS production goals that were developed for us by the Department of Energy. Thus, it has a strong link with national energy policy.

The proposed program provides for an equitable sharing of development benefits. Hydrocarbon supplies, if found in commercial quantities on the OCS, can generally be transported to demand areas, according to the Department of Energy. Thus, DOE has concluded that regional markets will not constrain OCS production. That is, because of the efficiency of oil and gas transport, the use of produced hydrocarbons from the OCS is not limited to only those areas adjacent to the production.

The proposed program provides for an equitable sharing of environmental risks since all offshore regions will be expected to contribute supplies if economically recoverable discoveries are made.

I have considered the laws, goals, and policies of affected States, including coastal zone management programs where they are approved. I do not believe that there are any laws, goals, or policies or coastal zone management programs which would preclude the initiation of planning for any sales on the proposed program. There are, certainly, differences of opinion with some States about the timing of some potential sales, but I believe that the concept of equitable sharing of benefits and risks requires that the start of planning not be precluded. After the planning is completed, I will be in a better position to decide whether the sale should go forward or not, if certain areas should be precluded from leasing, or if special lease terms and conditions are required to provide extra protection to particular environmental values or resource uses.

The frontier area sales have been selected in order to maximize the chances of discovering hydrocarbons. This means scheduling a number of first-ever sales off Alaska, where there is a general consensus that the potential is high. In regard to Alaska, I have designated a new leasing area north of the Alaska Peninsula and Unimak Island that is south of 56°30' North latitude and east of 165° West longitude. This area, the North Aleutian Shelf, was designated in order to start the consideration of this highly prospective location and at the same time provide protection for the exceptional marine resources in adjacent areas.

With respect to the two sales proposed off California in 1983 and 1984, I have not specified their location among the California leasing regions. This is because I expect that drilling of leased tracts and tracts soon to be leased may provide important information that will help us to better locate sales at a later date.

As you may know, my proposed schedule differs in some respects from the draft schedule that I asked the Govenors to review in March. It includes four more sales over the 5-year period, it is more compatible with the Department of Energy's production goals, and it provides for earlier exploration of frontier areas to improve the chances for discovering important new domestic supplies of oil and gas. The tools provided to me by the Outer Continental Shelf Lands Act Amendments of 1978 give me the basis for proposing a program of this level.

In implementing the program, timely development will continue to be a cornerstone. Lessees will be expected to complete sufficient exploration so that if conditions warrant, a good start can be made toward beginning production within the primary term of the case. It may be necessary to consider a longer than 5-year primary term in some new frontier areas, perhaps up to 10 years as is permitted by the 1978 Amendments to the OCS Lands Act.

The new 5-year program is not yet final. The law requires several more steps before I approve it early in 1980. Also, I have decided to prepare an environmental impact statement on the proposed schedule. Under our current timetable, the draft statement will be released in August of this year, and the final statement in January of next year before I finally approve the program.

I believe that it is in the interest of the nation to proceed with the proposed program. In order to provide the opportunity for us to do so, I have agreed to permit some of the early planning steps to take place before the final environmental statement is completed and the program is approved in 1980. These steps can be seen in the attached schedule. I want to assure you, however, that the start of planning is not an irrevocable commitment to lease sales. If the continuing reviews and comments show that it is in the national interest to change the timing of a proposed sale, I will certainly do so.

Sincerely,

Cecil D. Andrus,

Secretary.

Enclosures.

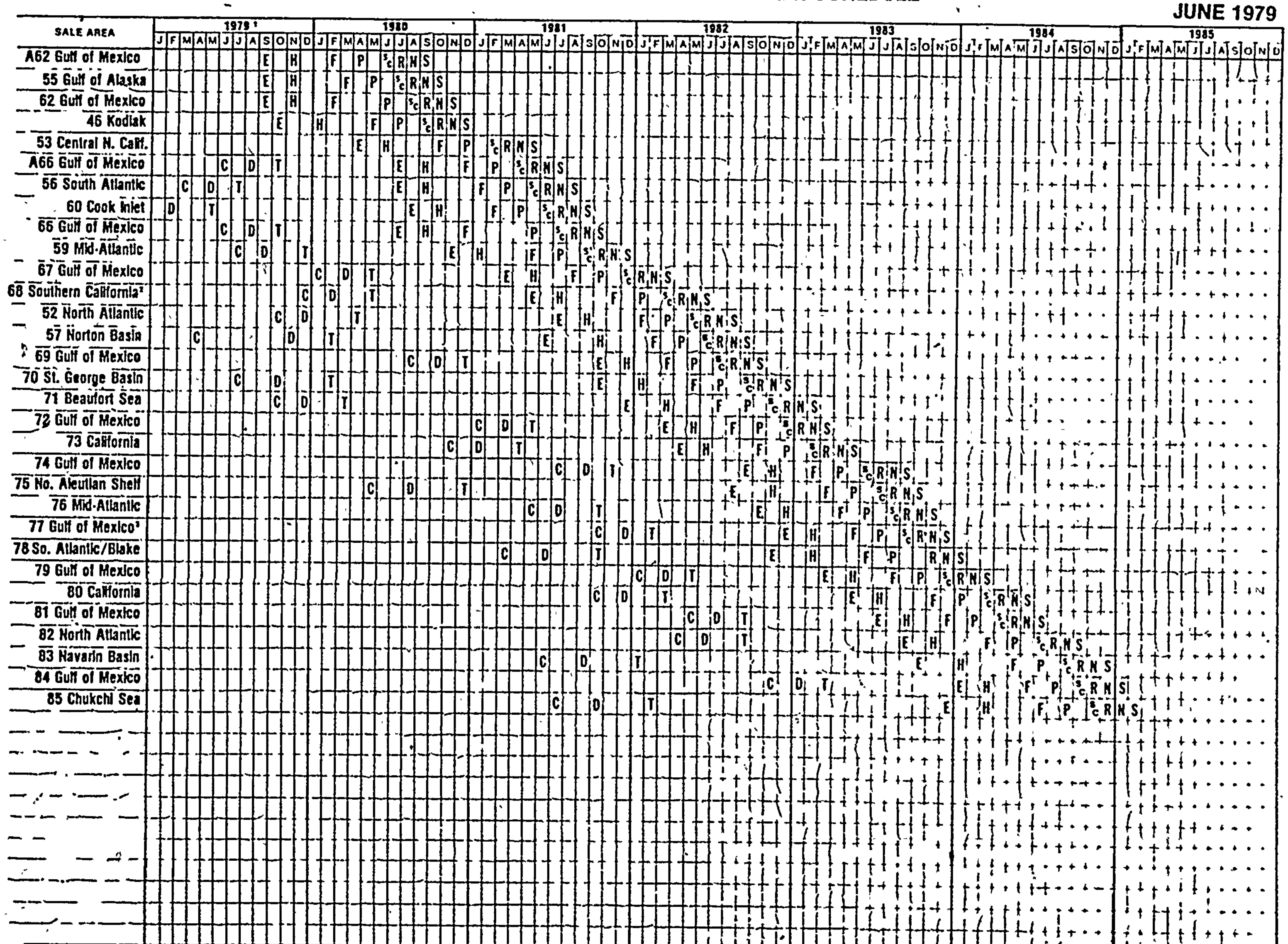
Identical letter sent to: Hon. Thomas P. O'Neill, Jr., Speaker of the House of Representatives.

BILLING CODE 4310-10-M

ATTACHMENT 1

PROPOSED OCS OIL AND GAS LEASE SALE SCHEDULE

JUNE 1979



C Call for Nominations
D Nominations Due
T Tentative Tract Selection
E Draft Environmental Statement
H Public Hearing
F Final Environmental Statement
P Proposed Notice of Sale
SC State Comments Due
R Energy Review
N Notice of Sale
S Sale

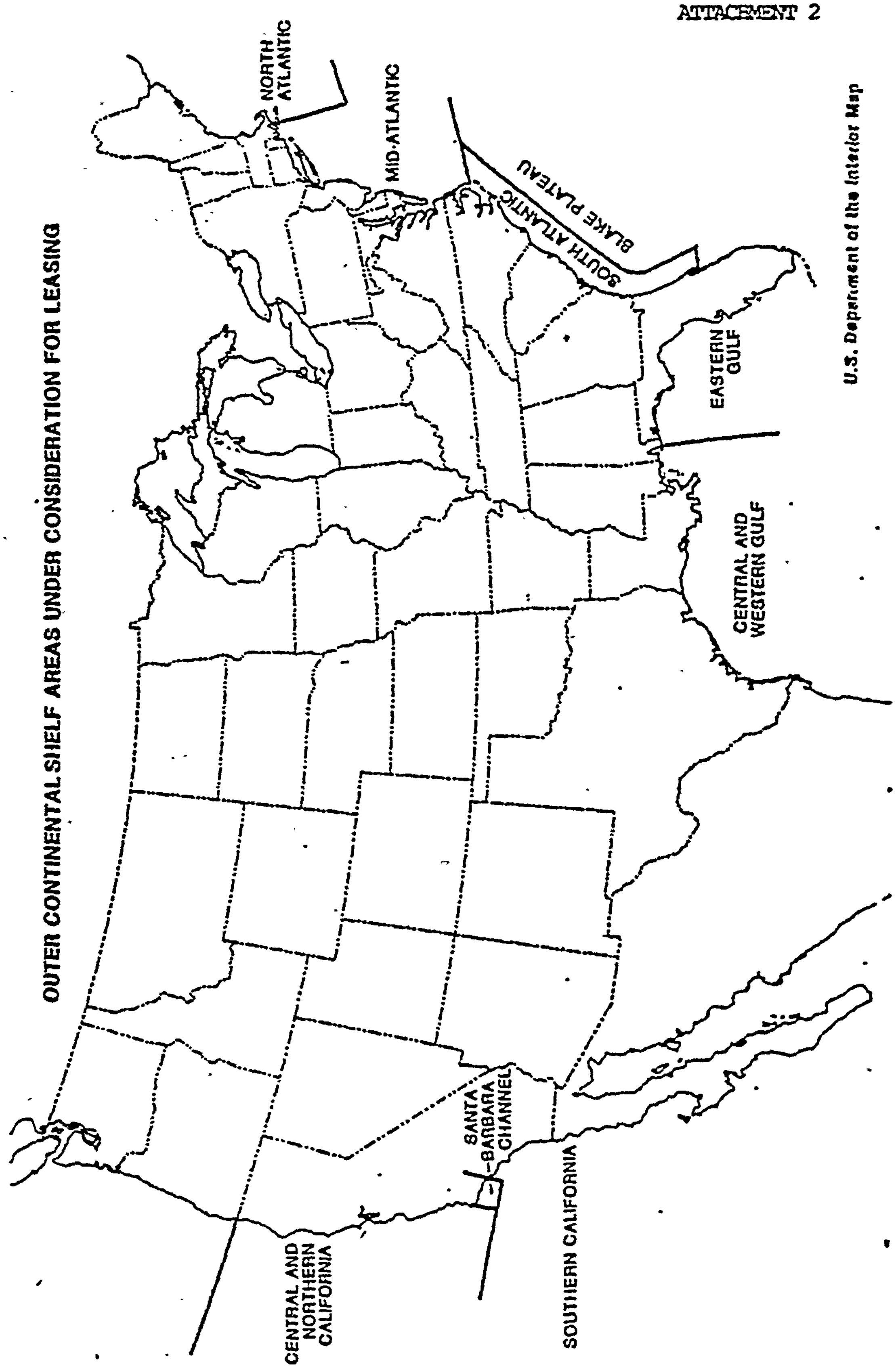
[1] The 1979 Column is included to indicate the pre-lease actions required for OCS lease sales scheduled for the period 3/80–2/85. Sales scheduled for dates in the latter half of 1979 include:
48 So. California June 1979
58A Gulf of Mexico Nov 1979
58 Gulf of Mexico July 1979
Beaufort Sea Dec. 1979
42 North Atlantic Oct 1979

[2] Includes Santa Barbara Channel.

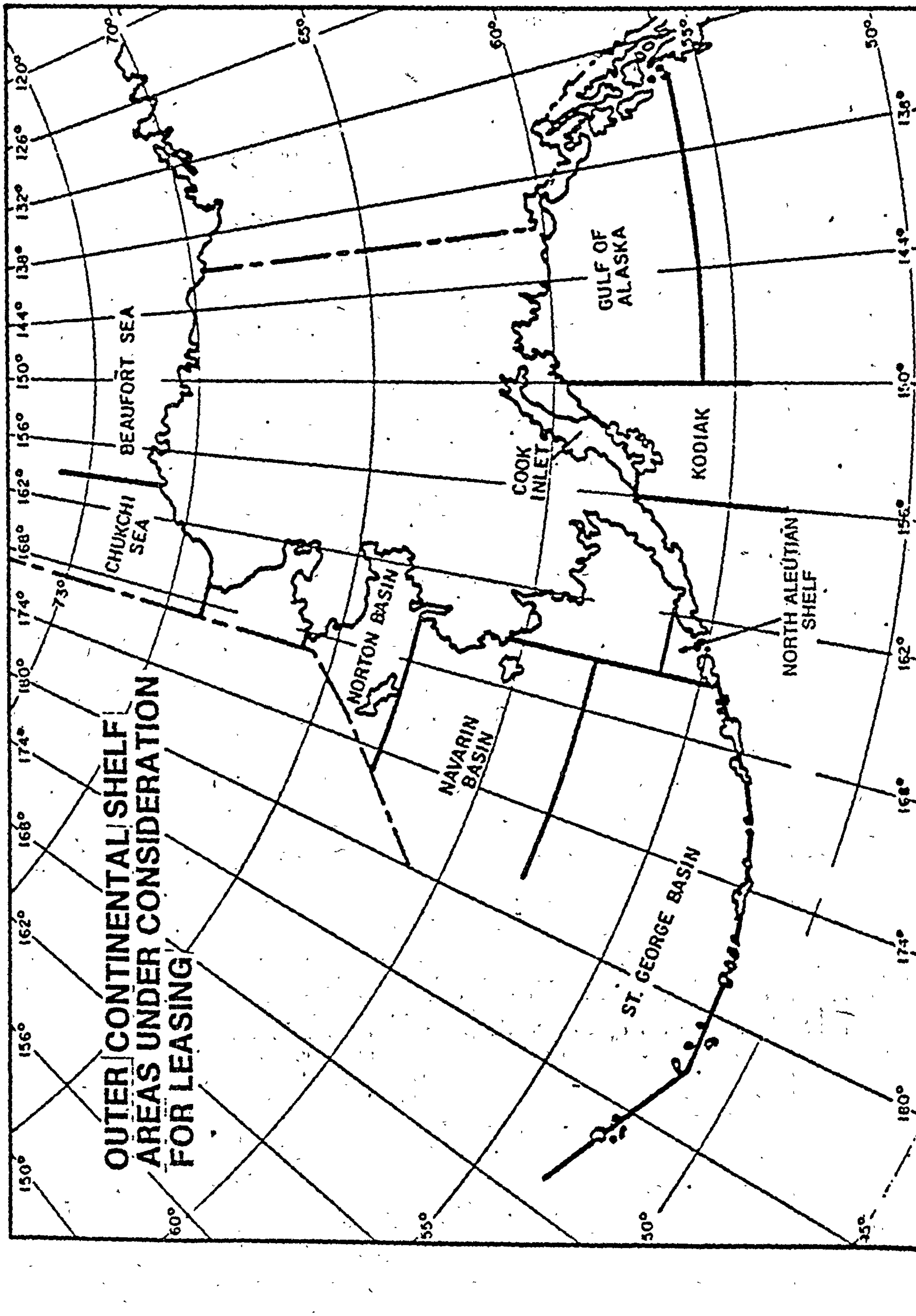
[3] This sale has been included in this schedule in order that planning may be commenced. Subsequent events (e.g. deletion of another sale from this schedule) will determine whether this sale will be held as indicated, held at some other time during the 5 year period, deleted or postponed until after February 1985.

ATTACHMENT 2

OUTER CONTINENTAL SHELF AREAS UNDER CONSIDERATION FOR LEASING



U.S. Department of the Interior Map


OUTER CONTINENTAL SHELF AREAS UNDER CONSIDERATION FOR LEASING
BEAUFORT SEA
CHUKCHI SEA
GULF OF ALASKA
COOK INLET
KODIAK
NORTH ALEUTIAN SHELF
NORTON BASIN
NAVARIN BASIN
ST. GEORGE BASIN

ATTACHMENT 3

June 1979

OCS Leasing Program

Size of Potential Sales

Area	Potential Size (millions of acres)
North Atlantic	0.8
Mid-Atlantic	0.8
South Atlantic	0.6
Blake Plateau	0.8
Gulf of Mexico	1.0
Southern California 1/	0.8
Central and Northern California	0.8
California	0.8
Gulf of Alaska	0.8
Cook Inlet	0.8
Kodiak	1.0
North Aleutian Shelf	1.0
St. George Basin	1.0
Navarin Basin	1.0
Norton Basin	0.6
Chukchi Sea	0.6
Beaufort Sea	0.6

1/ Includes Santa Barbara Channel.

ATTACHMENT 4

June 1979

Estimated Appropriations and Staff Requirements

for

Proposed 5-Year Leasing Program

Format

The following table provides estimates of appropriations and full-time permanent staff (FTP) necessary to support the proposed leasing program. It should be noted that this is an initial estimate and has not been evaluated through either internal or Office of Management and Budget processes and is subject to refinement.

The data are displayed in accordance with section 18(b) of the OCS Lands Act, as amended, which requires estimates of four specific activities. In addition, a general category, General Administrative Activities, was added to cover those costs not specifically required by section 18(b), but necessary in order to fully reflect the cost of managing the program. These five categories of activities are described below.

1. Obtain resource information and any other information required to prepare the leasing program (18(b)(1)). This includes the work performed by the USGS in preparing regional oil and gas resource assessments and tract-specific evaluations of common depth point and high-resolution seismic data. Also included is the biological resource information provided by FWS.

2. Analyze and intepret exploratory data and any other information that may be acquired under the OCS Lands Act, as amended (18(b)(2)). This activity covers the USGS operation of the OCS oil and gas information program mandated by the OCS Lands Act, as amended.

3. Conduct environmental studies and prepare environmental statements (18(b)(3)). This activity includes contract costs for the BLM environmental studies program (e.g., socio-economic, endangered species, resource conflicts). For the BLM, the figures also include $2.0 million and 51 FTP's in each year for the preparation of environmental statements which in the standard budget presentation are not included with the environmental studies program. The remaining FTP's (50 for each year) are for the support of the environmental studies program, appropriations for which are included in the activity, General Administrative Activities.

USGS funds and staff are used for regional assessments of geologic hazards used in summary reports prepared prior to the call for nominations and comments, more detailed analyses of geologic hazards and oil spill trajectory analysis used in the environmental statements prepared for potential sales, and for the preparation of development-stage environmental statements.

4. Supervise lease operations (18(b)(4)). This is a function of the USGS. It involves review of drilling, production and pipeline plans and operations, inspections of rigs and platforms to insure safety and compliance with regulations, and maintenance of royalty accounts.

5. General administrative activities. For the BLM, examples of general administrative activities include: the call for nominations and comments, tentative tract selection, public hearings on environmental statements, preparation of decision documents, support of the environmental studies program; post-sale analysis of bids; support of the Intergovernmental Planning Program for Leasing, Transportation and Facilities Siting; and analysis and approval of rights-of-way applications.

Examples of GS activities include analytical support and participation in most of the steps and activities mentioned in the preceding paragraph, and special support activities such as estuarine and coastal geologic investigations related to onshore impacts of OCS development.

The Fish and Wildlife Service, the Office of the Solicitor and the Office of OCS Program Coordination all participate in the management of the OCS program and all their costs are included in this activity other than the gathering and analyzing resource information by FWS.

Occasionally, other organizational units of the Department of the Interior, such as the National Park Service and the Bureau of Indian Affairs participate in the OCS program. However, since they do not have a continuing role and do not have specific staff and financial resources dedicated to the management of the OCS program, estimates for them are not included in this analysis.

Assumptions

The costs of the OCS program are a function of many variables, the most important of which are the number and geographic distribution of sales in any year and over the five-year schedule, and the type and extent of workload generated by a sale in a specific area. These cost estimates have been prepared using past experience in the program, e.g., knowledge of data needed to support the program, the costs and timing of data acquisition and average workload generated by a sale, the resources needed to supervise lease operations, as general guidelines. The bureaus can estimate from past experience what is likely to be required to support a sale in a particular sale area. For example, in Alaska, high resolution seismic data, acquired under contract, can cost up to twice as much as high resolution seismic data in the Mid-Atlantic; a development plan for a Gulf of Mexico lease would be expected sooner after the lease is awarded than one for a North Atlantic lease; weather conditions might seriously affect the environmental studies program in Alaska whereas off the lower 48 states weather conditions would not be as serious a constraint on data gathering. Costs of supervising are particularly subject to uncertainty since they depend on the level of exploration, development and production activities which will result during the 5-year period, both from sales on the proposed schedule and from earlier sales.

Comparison with FY 1980 Budget

The FY 1980 budget presently funds the OCS leasing program at $130.1 million and 1,479 FTP's. Specific funding is as follows:

	$ Millions	FTP
USGS	81.2	1,227
BLM	48.0	228
FWS	.3	6
OCS Coordination	.5	10
SOL	.3	8
	130.3	1,479

$34.7 million of BLM OCS budget and $5.7 million of USGS OCS budget is for environmental studies.

Estimated Appropriation and Staff Requirements for Proposed 5-Year OCS Leasing Program 1/

June 1979

Activity	FY 1980 $ million	FY 1980 FTP 2/	FY 1981 $ million	FY 1981 FTP	FY 1982 $ million	FY 1982 FTP	FY 1983 $ million	FY 1983 FTP	FY 1984 $ million	FY 1984 FTP	FY 1985 $ million	FY 1985 FTP
Resource Information:												
USGS	42.9	605	44.1	630	53.5	630	44.0	630	46.4	630	46.6	630
FWS	.2	5	.4	6	.5	8	.6	9	.7	11	.7	11
Total	43.1	610	44.5	636	54.0	638	44.6	639	47.1	641	47.3	641
Exploration Data:												
USGS	3.3	3	3.3	3	3.3	3	3.3	3	3.3	3	3.3	3
Environmental Statements and Studies:												
BLM 3/	41.8	101	39.8	101	28.6	101	23.9	101	23.2	101	21.2	101
USGS	9.8	78	9.9	79	9.9	79	9.9	79	9.9	79	9.9	79
Total	51.6	179	49.7	180	38.5	180	33.8	180	33.1	180	31.1	180
Supervise Lease Operations:												
USGS	30.7	505	32.9	513	38.1	597	41.1	631	43.5	673	43.9	673
General Administrative Activities:												
BLM	15.8	149	15.6	149	14.2	157	13.6	157	13.4	157	13.2	157
USGS	2.8	67	2.8	67	2.8	67	2.8	67	2.8	67	2.8	67
FWS	.1	2	.1	2	.1	2	.1	2	.1	2	.1	2
OCS Coordination	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
Solicitor	.4	11	.4	12	.4	13	.5	14	.5	14	.5	14
Total	19.6	239	19.4	240	18.0	249	17.5	250	17.3	250	17.1	250
Summary:												
BLM	57.6	250	55.4	250	42.8	258	37.5	258	36.6	258	34.4	258
USGS	89.5	1,258	93.0	1,292	107.5	1,376	101.0	1,410	105.9	1,452	106.5	1,452
FWS	.3	7	.5	8	.6	10	.7	11	.8	13	.8	13
OCS Coordination	.5	10	.5	10	.5	10	.5	10	.5	10	.5	10
Solicitor	.4	11	.4	12	.4	13	.5	14	.5	14	.5	14
Total	148.3	1,536	149.8	1,572	151.8	1,667	140.2	1,703	144.3	1,747	142.7	1,747

1/ Estimates do not include costs of studies, operations, assessment and administrative costs incurred during 5-year period for sales which will be held after February 1985.

2/ Full-time permanent positions.

3/ For each year, includes $2.0 million and 51 FTP's for preparation of environmental statements.

[FR Doc. 79-22583 Filed 7-20-79; 8:45 am]

BILLING CODE 4310-10-C

DEPARTMENT OF JUSTICE

Law Enforcement Assistance Administration

National Criminal Justice Information and Statistics Service; Statement of Policy

It is the intention of the Law Enforcement Assistance Administration to make all data and information from surveys, censuses, studies and reports sponsored by NCJISS available to all interested parties upon completion and verification of routine statistical procedures related to the data to be released. It is also the intention of LEAA to be in compliance with Directive No. 4, "Prompt Compilation and Release of Statistical Information" contained in the Statistical Policy Handbook issued May, 1978 by the Office of Federal Statistical Policy and Standards of the Department of Commere, and with LEAA regulations governing confidentiality of research and statistical data (28 CFR Part 22) which implement Section 524(a) of Crime Control Act of 1973, as amended.

The necessity for a data release policy has arisen from the expressed need for data by criminal justice officials and researchers prior to NCJISS issuing either a final or advance report containing the data being requested. This policy pertains exclusively to statistical series that produce non-individually identifiable data.

Therefore, in order to promote the early release of unpublished data to users who need the data for legitimate policy analyses, research and planning purposes, it is the expressed policy of LEAA and NCJISS that tabulated but unpublished data from statistical efforts sponsored by NCJISS may be released to institutional or individual data users upon request as soon as they become available, subject only to the following limitations:

(a) the tabulations to be released have been verified to the satisfaction of NCJISS and the collection/analysis agency or organization;

(b) the acquisition of the data by the requesting user will not, in the opinion of NCJISS, bestow special benefits, advantage or opportunity on that user;

(c) the requesting user agrees that there will be no formal release or publication of the data prior to NCJISS's final advance report containing that data.

The procedure to be followed by NCJISS in approving such early release of data will require a written request for either individual users or for classes of users that will indicate the manner in which the data are to be used, the urgency of that use justifying early release, and providing the assurance required by limitation (c) above. NCJISS will be the final judge of the merits of each request for unpublished data.

Benjamin H. Renshaw,

Acting Assistant Administrator, National Criminal Justice Information and Statistics Service.

[FR Doc. 79-22594 Filed 7-20-79; 8:45 am]

BILLING CODE 4410-18-M

NATIONAL FOUNDATION ON THE ARTS AND THE HUMANITIES

Media Arts Advisory Panel; Meeting

Pursuant to Section 10(a)(2) of the Federal Advisory Committee Act (Public Law 92-463), as amended, notice is hereby given that a meeting of the Media Arts Panel (Aid to Film/Video Section) will be held August 6 and 7, 1979, from 9:00 a.m. to 5:30 p.m., in room 1426, Columbia Plaza, 2401 E Street, NW., Washington, D.C.

This meeting is for the purpose of Panel review, discussion, evaluation, and recommendation on applications for financial assistance under the National Foundation on the Arts and the Humanities Act of 1965, as amended, including discussion of information given in confidence to the agency by grant applicants. In accordance with the determination of the Chairman published in the Federal Register of March 17, 1977, these sessions will be closed to the public pursuant to subsection (c) (4), (6) and (9)(B) of section 552 of Title 5, United States Code.

Further information with reference to this meeting can be obtained from Mr. John H. Clark, Advisory Committee Management Officer, National Endowment for the Arts, Washington, D.C. 20506, or call (202) 634-6070.

John H. Clark,

Director, Office of Council and Panel Operations, National Endowment for the Arts.

July 16, 1979.

[FR Doc. 79-22595 Filed 7-20-79; 8:45 am]

BILLING CODE 7537-01-M

DEPARTMENT OF ENERGY

Nuclear Regulatory Commission

Advisory Committee on Reactor Safeguards Subcommittee on Advanced Reactors; Meeeting

The ACRS Subcommittee on Advanced Reactors will hold an opening meeting on August 7, 1979 in Room 1046, 1717 H Street, N.W., Washington, DC, to continue its review of matters related to the NRC sponsored research on the safety of advanced reactor designs.

In accordance with the procedures outlined in the Federal Register on October 4, 1978 (43 FR 45926), oral or written statements may be presented by members of the public, recordings will be permitted only during those portions of the meeting when a transcript is being kept, and questions may be asked only by members of the Subcommittee, its consultants, and Staff. Persons desiring to make oral statements should notify the Designated Federal Employee as far in advance as practicable so that appropriate arrangements can be made to allow the necessary time during the meeting for such statements.

The agenda for subject meeting shall be as follows:

Tuesday, August 7, 1979, 8:30 a.m. until the conclusion of business.

The Subcommittee may meet in Executive Session, with any of its consultants who may be present, to explore and exchange their preliminary opinions regarding matters which should be considered during the meeting and to formulate a report and recommendations to the full Committee.

At the conclusion of the Executive Session, the Subcommittee will hear presentations by and hold discussions with representatives of the NRC Staff and their consultants, pertinent to the above topics. The Subcommittee may then caucus to determine whether the matters identified in the initial session have been adequately covered and whether additional meetings on this topic are necessary.

Further information regarding topics to be discussed, whether the meeting has been cancelled or rescheduled, the Chairman's ruling on requests for the opportunity to present oral statements and the time allotted therefore can be obtained by a prepaid telephone call to the Designated Federal Employee for this meeting, Dr. Richard Savio (telephone 202/634-3267) between 8:15 a.m. and 5:00 p.m., EDT.

Dated: July 16, 1979.

John C. Hoyle,

Advisory Committee Management Officer.

[FR Doc. 79-22470 Filed 7-20-79; 8:45 am]

BILLING CODE 7590-01-M

[Docket No. 50-155]

Consumers Power Co.; Proposed Issuance of Amendment to Facility Operating License

The United State Nuclear Regulatory Commission (the Commission) is considering issuance of an amendment to Facility Operating License No. DPR-6, issued to Consumers Power Company (the licensee), for operation of the Big Rock Point Plant (the facility) located in Charlevoix County, Michigan.

The amendment as proposed would allow the addition of three racks with a closer center-to-center spacing of spent fuel assemblies in the facility's spent fuel pool with a resultant increase in the storage capacity from 193 to 441 fuel assemblies.

Prior to issuance of the proposed license amendment, the Commission will have made findings required by the Atomic Energy Act of 1954, as amended (the Act) and the Commission's regulations.

By August 22, 1979, the licensee may file a request for a hearing with respect to issuance of the amendment to the subject facility operating license and any person whose interest may be affected by this proceeding may file a request for a hearing in the form of a petition for leave to intervene with respect to the issuance of the amendment to the subject facility operating license. Requests for a hearing and petitions for leave to intervene shall be filed in accordance with the Commission's "Rules of Practice for Domestic Licensing Proceedings" in 10 CFR Part 2. If a request for a hearing or petition for leave to intervene is filed by the above date, the Commission or an Atomic Safety and Licensing Board, designated by the Commission or by the Chairman of the Atomic Safety and Licensing Board Panel, will rule on the request and/or petition and the Secretary or the designated Atomic Safety and Licensing Board will issue a notice of hearing or an appropriate order.

As required by 10 CFR 2.714, a petition for leave to intervene shall set forth with particularity the interest of the petitioner in the proceding, and how that interest may be affected by the results of the proceeding. The petition should specifically explain the reasons why intervention should be permitted with particular reference to the following factors: (1) The nature of the petitioner's right under the Act to be made a party to the proceeding; (2) the nature and extent of the petitioner's property, financial, or other interest in the proceeding; and (3) the possible effect of any order which may be entered in the proceeding on the petitioner's interest. The petition should also identify the specific aspect(s) of the subject matter of the proceeding as to which petitioner wishes to intervene. Any person who has filed a petition for leave to intervene or who has been admitted as a party may amend the petition without requesting leave of the Board up to fifteen (15) days prior to the first prehearing conference scheduled in the proceeding, but such an amended petition must satisfy the specificity requirements described above.

Not later than fifteen (15) days prior to the first prehearing conference scheduled in the proceeding, a petitioner shall file a supplement to the petition to intervene which must include a list of the contentions which are sought to be litigated in the matter, and the bases for each contention set forth with reasonable specificity. Contentions shall be limited to matters within the scope of the amendment under consideration. A petitioner who fails to file such a supplement which satisfies these requirements with respect to at least one contention will not be permitted to participate as a party.

Those permitted to intervene become parties to the proceeding, subject to any limitations in the order granting leave to intervene, and have the opportunity to participate fully in the conduct of the hearing, including the opportunity to present evidence and cross-examine witnesses.

A request for a hearing or a petition for leave to intervene shall be filed with the Secretary of the Commission, United States Nuclear Regulatory Commission, Washington, D.C. 20555, Attention: Docketing and Service Section, or may be delivered to the Commission's Public Document Room, 1717 H Street, N.W., Washington, D.C. by the above date. Where petitions are filed during the last ten (10) days of the notice period, it is requested that the petitioner or representative for the petitioner promptly so inform the Commission by a toll-free telephone call to Western Union at (800)-325-6000. The Western Union operator should be given Datagram Identification Number 3737 and the following message addressed to Dennis L. Ziemann: petitioner's name and telephone number; date petition was mailed; plant name; and publication date and page number of this Federal Register notice. A copy of the petition should also be sent to the Executive Legal Director, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, and to Judd L. Bacon, Esquire, Consumers Power Company, 212 West Michigan Avenue, Jackson, Michigan 49201, attorney for the licensee.

Nontimely filings of petitions for leave to intervene, amended petitions, supplemental petitions and/or requests for hearing will not be entertained absent a determination by the Commission, the presiding officer or the Atomic Safety and Licensing Board designated to rule on the petition and/or request, that the petitioner has made a substantial showing of good cause for the granting of a late petition and/or request. That determination will be based upon a balancing of the factors specified in 10 CFR 2.714(a)(i)-(V) and 10 CFR 2.714(d).

For further details with respect to this action, see the application for amendment dated June 26, 1979, and the supporting safety and environmental analyses submitted by the licensee's letter dated April 23, 1979, which are available for public inspection at the Commission's Public Document Room, 1717 H Street, N.W., Washington, D.C., and at the Charlevoix Public Library, 107 Clinton Street, Charlevoix, Michigan 49720.

Dated at Bethesda, Maryland this 17th of July, 1979.

For the Nuclear Regulatory Commission.

Richard D. Silver,

Acting Chief, Operating Reactors Branch #2, Division of Operating Reactors.

[FR Doc. 22666 Filed 7-20-79 8:45 am]

BILLING CODE 7590-01-M

[Dockets Nos. 50-269, 50-270, and 50-287]

Duke Power Co.; Issuance of Amendments to Facility Operating Licenses

The U.S. Nuclear Regulatory Commission (the Commission) has issued Amendments Nos. 74, 74 and 71 to Facility Operating Licenses Nos. DPR-38, DPR-47 and DPR-55, respectively, issued to Duke Power Company (the licensee), which revised Technical Specifications for operation of the Oconee Nuclear Station, Units Nos. 1, 2 and 3, located in Oconee County, South Carolina. The amendments are effective as of the date of issuance.

The amendments revise the Technical Specifications by redesignating the inspection category of hydraulic shock suppressor 2-130, deleting hydraulic suppressors replaced by mechanical suppressors, and making error corrections and other minor changes.

The application for the amendments complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations. The Commission has made appropriate findings as required by the Act and the Commission's rules and regulations in 10 CFR Chapter I, which are set forth in the license amendments. Prior public notice of these amendments was not required since the amendments do not involve a significant hazards consideration.

The Commission has determined that the issuance of these amendments will not result in any significant environmental impact and that pursuant to 10 CFR § 51.5(d)(4) an environmental impact statement or negative declaration and environmental impact appraisal need not be prepared in connection with the issuance of these amendments.

For further details with respect to this action, see (1) the application for amendments dated August 22, 1978, as supplemented April 30, 1979, (2) Amendments Nos. 74, 74 and 71 to Licenses Nos. DPR-38, DPR-47 and DPR-55, respectively, and (3) the Commission's related Safety Evaluation. All of these items are available for public inspection at the Commission's Public Document Room, 1717 H Street, NW, Washington, D.C., and at the Oconee County Library, 201 South Spring Street, Walhalla, South Carolina. A copy of items (2) and (3) may be obtained upon request addressed to the U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, Attention: Director, Division of Operating Reactors.

Dated At Bethesda, Maryland, this 10th day of July 1979.

For the Nuclear Regulatory Commission.

Robert W. Reid,

Chief, Operating Reactors Branch #4, Division of Operating Reactors.

[FR Doc. 79-22866 Filed 7-20-79; 8:45 am]

BILLING CODE 7590-01-M

[Docket Nos. 50-346A, 50-440A, and 50-441A]

Toledo Edison Co.; the Cleveland Electric Illuminating Co., et al.

The Director, Office of Nuclear Reactor Regulation has issued an order dated July 16, 1979. The order reads as follows:

"On June 25, 1979 this office issued an "Order Modifying Antitrust License Condition No. 3 of Davis-Besse Unit 1, License No. NPF-3 and Perry Units 1 and 2, CPPR-148, CPPR-149" in the captioned matter. That Order amended, effective immediately, Antitrust License Condition No. 3 contained in the above listed license and construction permits. The amendment required the Cleveland Electric Illuminating Company (CEI) to file a specific transmission tariff with the Federal Energy Regulatory Commission (FERC). CEI was given twenty days from the receipt of the Order to request a hearing with respect to all or any part of the amendment and twenty-five days from the receipt of the Order to file the specific transmission tariff with the FERC.

"Pursuant to 10 CFR 2.204 of the Commissions Rules of Practice.It Is Hereby Ordered That: The times afforded to CEI to request a hearing and to file the transmission tariff with the FERC are extended for fifteen (15) days respectively from the receipt of this Order."

For the Nuclear Regulatory Commission.

Dated at Bethesda, Maryland this 16th day of July, 1979.

Jerome Saltzman,

Chief, Antitrust and Indemnity Group, Office of Nuclear Reactor Regulation.

[FR Doc. 79-22865 Filed 7-20-79; 8:45 am]

BILLING CODE 7590-01-M

Financial Protection Requirements and Indemnity Agreements; Section 82—Procedures

Pursuant to its authority under Section 11(j) of the Atomic Energy Act of 1954, as amended, 42 U.S.C. 2014(j), and according to § 140.82 of its regulations, 10 CFR 140.82, the Commission hereby initiates the making of a determination as to whether or not the recent accident at Three Mile Island, Unit 2, constitutes an extraordinary nuclear occurrence ("ENO"). Although no petitions requesting such a determination have as yet been received, the Commission is aware of several factors which indicate that proceeding with the determination at this time is in the public interest. First, it is clear that the events which have taken place at Three Mile Island, Unit 2, constitute the most serious nuclear accident to date at a licensed U.S. facility, and thus should be rigorously scrutinized from the standpoint of their effect on the public. Second, various lawsuits have been brought concerning this accident, and the determination of whether or not an extraordinary nuclear occurrence has taken place is pertinent to issues which may arise in those cases. The court has informally asked the Commission for its view on the ENO question, and the Commission would like to assist the court in this regard.

The Commission invites interested persons to submit to the Commission, within thirty days of this announcement, any information in their possession relevant to this determination. Submittals should, if possible, focus on the application of the Commission's regulations, 10 CFR 140.84 and 140.85, to the consequence of the Three Mile Island, Unit 2, accident. This information, along with other information assembled by the Commission from its own and other sources, will be considered by a panel composed of Commission principal staff as required by 10 CFR 140.82(b). The composition of this panel, and the detailed procedures which the Commission proposes to follow, including further provision for public participation, will be announced at a later date. Submittals should be sent to the Secretary of the Commission, U.S. Nuclear Regulatory Commission, 1717 H Street, NW., Washington, D.C., 20555.

Contact: Ira P. Dinitz, 301-492-8336.

Dated at Washington, D.C., this 8th day of July 1979.

For the Commission.

Samuel J. Chilk,

Secretary of the Commission.

Background Information

Introduction

If a nuclear incident occurs, one of the principal obstacles to a claimant's recovery for injuries or damages could be the necessity of proving negligence on the part of the utility or other defendants. In 1966 Congress attempted to remove this obstacle for certain nuclear incidents ("extraordinary nuclear occurrences"—ENO) through contractual provisions termed "waivers of defenses," resulting in an essentially no-fault scheme. These waivers were intended to expedite recovery for claims under the Price-Anderson Act in the event of an ENO. The following is intended to explain the waiver of defenses in greater detail and to describe the criteria used by the NRC in making a finding as to whether or not an ENO has occurred. In order to better understand the waiver provision and the concept of an ENO, an overview of the Price-Anderson Act is included.

I. Overview of the Price-Anderson Act. Under the Price-Anderson Act, (which is a part of the Atomic Energy Act of 1954) there is a system of private funds and government indemnity totalling $560 million to pay public liability claims for personal injury and property damage resulting from a "nuclear incident." The Price-Anderson Act, which expires August 1, 1987, requires licensees of large commercial nuclear power plants to provide proof to the NRC that they have financial protection in the form of private nuclear liability insurance, or in some other form approved by the Commission, in an amount equal to the maximum amount of liability insurance available from private sources. That financial protection, $475 million at the time of the Three Mile Island (TMI) accident on March 28, 1979, consists of primary private nuclear liability insurance of $140 million provided by two insurance pools, American Nuclear Insurers (ANI) and Mutual Atomic Energy Liability Underwriters (MAELU) (which was increased to $160 million on May 1, 1979—except for TMI) and a secondary layer. In the event of a nuclear incident causing damages exceeding $140 million, each commercial nuclear power plant licensee would be charged by the insurance pools providing the insurance a prorated share of damages in excess of the primary insurance layer up to $5 million per reactor per incident. With 67 large commercial reactors now operating under this system, the secondary insurance layer totals $335 million. Thus, the two layers of insurance at the time of the TMI accident totaled $475 million. The difference of $85 million between the financial protection layers of $475 million and the $560 million liability limit established by the Price-Anderson Act is provided by government indemnity. Government indemnity will gradually be phased out as more commercial reactors are licensed and licensees participate in the second layer of insurance. When the primary and secondary layers by themselves provide liability coverage of $560 million, government indemnity will be eliminated. The liability limit—now $560 million—would thereafter increase in increments of $5 million for each new commercial reactor licensed to operate.

II. Extraordinary Nuclear Occurrence—General. A. *Definition.* Webster defines the term "extraordinary" as "going beyond what is usual, regular, or customary." Viewed in this light, the recent events at Three Mile Island may be termed extraordinary, since they would not occur during normal operations at a nuclear power plant. However, the term "extraordinary nuclear occurrence" (ENO) is precisely defined by the Price-Anderson Act as follows:

The term "extraordinary nuclear occurrence" means any event causing a discharge or dispersal of source, special nuclear, or byproduct material from its intended place of confinement in amounts offsite, or causing radiation levels offsite, which the Commission determines to be substantial, and which the Commission determines has resulted or probably will result in substantial damages to persons offsite or property offsite. (Atomic Energy Act (as amended), subsection 11j, 42 U.S.C. 2014j)

The definition thus provides a two-pronged test: (1) Substantial offsite release of radioactive material or substantial offsite radiation, *and* (2) substantial offsite damages. This same section requires that the Commission "establish criteria in writing" for purposes of applying these tests to specific events.

The significance of the ENO concept is that a positive determination that an ENO has taken place must be made by the Commission before the "waiver of defenses" provisions of the Act, described below, can apply to the accident. In the event of a "nuclear incident" that is declared *not* to be an ENO, Price-Anderson funds are still available and normal defenses permitted under State law are not waived. The insurance pools may dispense funds under their policies, whether or not there is a determination by the Commission of an ENO, and in certain situations at TMI have already done so.

B. *Legislative History.* Congressional reports and statements by members of Congress in 1966, during the passage of the ENO and related provisions, give a clear impression of Congressional intent. On one hand, it was felt that if recovery of Price-Anderson funds were left entirely to the statutes and principles of State tort law in the event of a major nuclear accident, many valid claims might be tied up in the courts for years. Congress gave particular attention to problems of varying State statutes of limitations (some States, for example, had not adopted the "discovery" rule for concealed injuries—which would run the statute of limitations from the time the injured party knew of or reasonably should have discovered his injury). Congress was also concerned with the possibility that some States might not apply "strict liability" to a nuclear accident so that injured parties might have to prove negligence. On the other hand, there was considerable resistance to the total substitution of State law by creation of a "Federal tort" for nuclear accidents.

The result of this balance of competing factors was the "waiver" system. Under this system the NRC could require that its licensees agree to waive certain State law defenses (contributory negligence, assumption of risk, etc.) as part of the indemnity and insurance agreements, and thus create "strict liability" through the insurance policies and indemnity agreements. A statute of limitations would also be incorporated into these agreements, which would come into play if state statute of limitations were more restrictive. Finally, a consolidated Federal court proceeding would be used to handle all claims in the new system.

Insurers feared, however, that under such a waiver system they would be subjected to "nuisance suits." The insurance industry felt that it should not be required to waive the usual defenses available to it under State tort law for those "nuclear incidents" which had resulted in, at most, minor offsite releases and property damage. The insurance pools urged that such cases could be, and should be, dealt with within the usual State tort law system, particularly since minor accidents would not give rise to the need for quick, massive recoveries.

To meet this concern, Congress developed the "ENO" concept. The waiver provisions would be activated only if an "extraordinary nuclear occurrence" took place. The ENO was intended to be an event causing *both* substantial offsite releases of radiation and substantial offsite damages to persons or property. The Commission was given broad discretion (free of judicial review) to determine what constitutes an ENO, but was required by the 1966 amendments to publish written criteria which would be adopted after a public rulemaking process.

Congressional statements indicate that application of the criteria would be relatively flexible, even though precise numbers (such as a $5 million damage figure) would be selected in the rulemaking. There is no indication that Congress intended the Commission to apply its criteria in a rigid fashion. Still, it is equally clear that Congress did desire a reasonably specific index of what the Commission considered "substantial" for purposes of an ENO determination.

C. *Waivers of Defenses.* When the Commission determines that an ENO has occurred, then any defendant must waive:

(1) Any issue or defense as to the conduct of the claimant or fault of persons indemnified,

(ii) Any issue or defense, as to charitable or governmental immunity, and

(iii) Any issue or defense based on any statute of limitations if suit is instituted within three years from the date on which the claimant first knew, or reasonably could have known, of his injury or damage and the cause thereof, but in no event more than twenty years after the date of the nuclear incident.

The waivers in subsection (i) relating to the fault of all persons indemnified relieve the claimant of having to prove negligence by any defendant and of having to disprove defenses such as contributory negligence. To recover for damages resulting from an ENO, a claimant needs to prove that he was injured or damaged, the monetary amount of the damages, and the causal link between his damages and the radioactive, toxic, explosive or other hazardous properties of the radioactive material released. Thus, through this "no-fault" type of provision the principal obstacle to a claimant's recovery is no longer proving negligence on the part of the defendant but rather showing that his injury or damage was caused by the ENO.

The statute of limitations provision in subsection (iii) of the waivers is not intended to be more restrictive than applicable State law. Thus, if a State had a statute of limitations which provided that suits for personal injury or property damage resulting from a nuclear incident could be brought any time within 30 years after the occurrence of the incident, the 30-year statute would take precedence over the 20-year period specified in the Price-Anderson Act.

The criteria to be used by the Commission will be fully discussed later, but at this point it should be reiterated that, unless an ENO is declared by the Commission, the waivers of defenses provisions do not apply. In such a situation a claimant would have exactly the same rights that he now has under existing tort law.

The other major concept in the 1966 amendments is that the Commission's authority to determine whether or not an ENO has occurred is not reviewable by the courts.

The 1966 amendments also benefited injured persons in several other respects. The Commission was authorized to make financial assistance payments to claimants immediately following a nuclear incident, regardless of whether an ENO determination has been made and without requiring them to sign a release or otherwise compromise their claims. In the event of an ENO, the 1966 amendments authorized all claimants to sue in the same Federal district court, generally under the same rules of procedure. Any action dealing with the same incident but pending in any State court or other Federal district court could, upon motion of the NRC or defendant, be removed to the single specified district court. Consolidation of all claims resulting from an ENO in a single Federal district court would permit all claimants to be treated equally. Finally, the 1966 amendments modified the Act to assure that available funds would be distributed in accordance with a court-approved plan making appropriate allowance for latent injury claims if it appeared that the total amount of all claims might exceed the limit on liability.

III. Criteria for Determining an ENO

A. *Language and Structure of the Criteria.* For the Commission to make the determination that there has been an ENO both Criterion I and Criterion II as set out in the Commission's published regulations (Title 10, Code of Federal Regulations, §§ 140.84 and 140.85) must be met. The language of the criteria (especially Criterion I) is rather technical and precise and is expressed in terms of measurements that laymen would not be expected to make themselves. For example, to satisfy Criterion I the Commission must determine that there has been a substantial discharge or dispersal of radioactive material off the site of the reactor, or that there has been a substantial level of radiation offsite. The Commission would determine that Criterion I had been met when, as a result of an event comprised of one or more related happenings, radioactive material is released from its intended place of confinement or radiation levels occur offsite and *either* of the following findings are also made.

a. The Commission finds that one or more persons offsite were, could have been, or might be exposed to radiation or to radioactive material, resulting in a dose or in a projected dose in excess of one of the levels in the following table:

Total Projected Radiation Doses

Critical organ:	*Dose (rems)*
Thyroid	30
Whole body	20
Bone Marrow	20
Skin	60
Other organs or tissues	30

In measuring or projecting doses, exposures from the following types of radiation shall be included:

(1) Radiation from sources external to the body;

(2) Radioactive material that may be taken into the body from air or water; and

(3) Radioactive material that may be taken into the body from food or from land surfaces.

(or)

b. The Commission finds that—

(1) As the result of a release of radioactive material from a reactor there is at least a total of any 100 square meters of offsite property that has surface contamination. This contamination must show levels of radiation in excess of one of the values listed in column 1 or column 2 of the following table, *or*

(2) As the result of a release of radioactive material in the course of transportation surface contamination of any offsite property has occurred. This contamination must show levels of radiation in excess of one of the values listed in column 2 of the following table.

Total Surface Contamination Levels [1]

Type of emitter	Column 1 Utility's property beyond the fence surrounding the reactor station	Column 2 Other offsite property
Alpha emmission from transuranic isotopes	3.5 microcuries per square meter	0.35 microcuries per square meter.
Alpha emmission from isotopes other than transuranic isotopes.	35 microcuries per square meter	3.5 microcuries per square meter.
Beta or gamma emmission	40 millirads/hour at 1 cm. (measured through not more than 7 milligrams per square centimeter of total absorber).	4 millirads/hour at 1 cm. (measured through not more than 7 milligrams per square centimeter of total absorber).

[1] The maximum levels (above background), observed or projected, 8 or more hours after initial deposition.

Based on the information available to the NRC staff at this time, it appears that neither part of Criterion I is satisfied. Both personal, exposures and property contamination are presently considered to be far below the levels specified in the tables set out above. In the period March 28–April 7, the approximate upper limit on whole body dose to a person in a populated area offsite has been calculated to be 100 millirems. For the most part, property contamination levels measured approximated "minimum detectable activity" levels.

If the Commission determines that an event satisfied Criterion I, Criterion II must then be applied. If Criterion I cannot reasonably be met, the Commission would conclude that there has not been an ENO. Criterion II is satisfied if the Commission makes *any* of the following findings:

(1) The event has resulted in the death or hospitalization, within 30 days of the event, of five or more people located offsite showing objective clinical evidence of physical injury from exposure to the radioactive, toxic, explosive or other hazardous properties the reactor's nuclear material; *or*

(2) $2,500,000 or more of damage offsite has been or will probably be sustained by any one person, or $5 million or more of such damage in total has been or will probably be sustained, as the result of such event; *or*

(3) The Commission finds that $5,000 or more of damage offsite has been or will probably be sustained by each of 50 or more persons, provided that $1 million or more of such damage in total has been or will probably be sustained, as the result of such event.

The term "damage" refers to damage arising out of or resulting from the radioactive, toxic, explosive, or other hazardous properties of the reactor's nuclear material, and shall be based upon estimates of one or more of the following:

(1) Total cost necessary to put affected property back into use,

(2) Loss of use of affected property,

(3) Value of affected property where not practical to restore to use,

(4) Financial loss resulting from protective actions such as evacuation, appropriate to reduce or avoid exposure to radiation or to radioactive materials.

Based on the information available to the NRC staff at this time, the only category of Criterion II damages possibly satisfied by the Three Mile Island accident is defined by (4), namely financial loss resulting from protective actions such as evacuation, appropriate to reduce or avoid exposure to radiation or radioactive material. A limited number of persons (pregnant women and small children) were advised by the Governor of Pennsylvania to leave the 5 mile radius of Three Mile Island, and in so doing incurred expenses. The insurance pools have been compensating the expenses of these families. Many others evacuated the area although they were not advised to do so.

A detailed assessment of all losses of this type might reach the $5 million figure of Criterion II, though much would depend on how broadly the various damage categories of this criterion were interpreted. It appears unlikely that voluntary payments by the insurance pools will reach this figure. The amount recoverable in the various court actions is virtually impossible to estimate at this time.

The 1966 amendments to the Act required the Commission to prepare and publish for public comment the criteria it proposed to apply in deciding whether a nuclear incident was an ENO. On May 9, 1968, the proposed rule and accompanying explanation appeared in the Federal Register (33 FR 6978). Following a period of public comment, the final rule was published on September 1, 1968 with an effective date of December 1, 1968 (33 FR 15998).

The dual criteria contained in the final rule were designed to follow the language of the 1966 amendments to the Act in defining an ENO: there must be a substantial offsite release *and* substantial offsite damages. The specific values incorporated into the criteria intentionally place a large gap between an ENO and the Commission's regulations governing offsite release during normal operations. Those values were intended to represent the Atomic Energy Commission's best judgment in deciding when the Act's definition of an ENO had been satisfied. The criteria have remained unchanged since their adoption in 1968.

[FR Doc. 79-22689 Filed 7-20-79; 8:45 am]

BILLING CODE 7590-01-M

OFFICE OF MANAGEMENT AND BUDGET

Agency Forms Under Review

Background

When executive departments and agencies proposed public use forms, reporting, or recordkeeping requirements, the Office of Management and Budget (OMB) reviews and acts on those requirements under the Federal Reports Act (44 U.S.C. Chapter 35). Departments and agencies use a number of techniques including public hearings to consult with the public on significant reporting requirements before seeking OMB approval. OMB in carrying out its responsibility under the Act also considers comments on the forms and recordkeeping requirements that will affect the public.

List of Forms Under Review

Every Monday and Thursday OMB publishes a list of the agency forms received for review since the last list was published. The list has all the entries for one agency together and grouped into new forms, revisions, extensions, or reinstatements. Each entry contains the following information:

The name and telephone number of the agency clearance officer;
The office of the agency issuing this form;
The title of the form;
The agency form number, if applicable;
How often the form must be filled out;
Who will be required or asked to report;
An estimate of the number of forms that will be filled out;
An estimate of the toal number of hours needed to fill out the form; and
The name and telephone number of the person or office responsible for OMB review.

Reporting or recordkeeping requirements that appear to raise no significant issues are approved promptly. In addition, most repetitive reporting requirements or forms that require one half hour or less to complete and a total of 20,000 hours or less annually will be approved ten business days after this notice is published unless specific issues are raised; such forms are identified in the list by an asterisk (*).

Comments and Questions

Copies of the proposed forms and supporting documents may be obtained from the agency clearance officer whose name and telephone number appear under the agency name. Comments and questions about the items on this list should be directed to the OMB reviewer or office listed at the end of each entry.

If you anticipate commenting on a form but find that time to prepare will prevent you from submitting comments promptly, you should advise the reviewer of your intent as early as possible.

The timing and format of this notice have been changed to make the publication of the notice predictable and to give a clearer explanation of this process to the public. If you have comments and suggestions for further improvements to this notice, please send them to Stanley E. Morris, Deputy Associate Director for Regulatory Policy and Reports Management, Office of Management and Budget, 726 Jackson Place, Northwest, Washington, D.C. 20503.

DEPARTMENT OF COMMERCE

Agency Clearance Officer—Edward Michaels—377-4217

Extensions

National Oceanic and Atmospheric Administration
Shrimp Log Book Form
NOAA 88-24
Monthly
U.S. owned shrimp companies in South America, 1,680 responses; 2,806 hours
Richard Sheppard, 395-3211

DEPARTMENT OF ENERGY

Agency Clearance Officer—John Gross—252-5214

New forms

Survey of residential fuel oil inventories
EIA-410
Single time
Indiv. households and fuel oil suppliers, 2,226 responses; 467 hours
Jefferson B. Hill, 395-5867

Survey of coal industry training programs
IR-180
Single time
Coal companies, 351 responses; 351 hours
Jefferson B. Hill, 395-5867

Useable fuel inventories
EIA-403
Monthly
Firms which gen. elect. from oil fired equipment, 4,500 responses; 4,500 hours
Jefferson B. Hill, 395-5867

*Secondary inventories survey
EIA-408
Monthly
Sample of manufacturing firms, 60,000 responses; 15,000 hours
Jefferson B. Hill, 395-5867

Revisions

National survey of fuel purchases for vehicles
EIA-141
On occasion
Sample of households chosen from EIA-84, 2,252 responses; 1,919 hours
Jefferson B. Hill, 395-5867

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Agency Clearance Officer—Peter Gness—245-7488

New forms

Food and Drug Administration
Survey of State interest in educational initiative on diagnostic radiation
Single time
State health agencies, 100 responses; 50 hours
Richard Eisinger, 395-3214

Office of Education
Lender's Application for Insurance Claim on Federal Insured Student Loan
OE 1207
On occasion
Banks, credit unions, lending institutions, 277,500 responses; 23,125 hours
Laverne V. Collins, 395-3214

Revisions

Food and Drug Administration

Medicated Feed Application
FD 1800
On occasion
Feed mills and farms mixing medicated feeds, 5,500 responses; 11,000 hours
Richard Eisinger, 395-3214

DEPARTMENT OF LABOR

Agency Clearance Officer—Philip M. Oliver—523-6341

Revisions

Employment Standards Administration
*Application for lump sum award
LS-221
On occasion
Claimants rec. workers' disability or death bene., 20 responses; 10 hours
Arnold Strasser, 395-5080

ENVIRONMENTAL PROTECTION AGENCY

Agency Clearance Officer—John J. Stanton—245-3064

Revisions

*Non-compliance of motor vehicles with Federal emissions standards
On occasion
Owners of suspect veh., dealers, fleets, repair facil., 6,700 responses, 1,542 hours
Edward H. Clarke, 395-5867

*Emission Factors Survey
On occasion
Motor veh. owners in 10-12 major metrop. areas, 10,000 responses; 5,000 hours
Edward H. Clarke, 395-5867

SMALL BUSINESS ADMINISTRATION

Agency Clearance Officer—John Reidy—653-6081

Reinstatements

*Application for Surety Bond Guarantee Assistance
SBA 994
On occasion
Small contractors requesting assistance, 34,000 responses; 8,500 hours
Richard Sheppard, 395-3211

Stanley E. Morris,
Deputy Associate Director for Regulatory Policy and Reports Management.

[FR Doc. 79-22710 Filed 7-20-79; 8:45 am]
BILLING CODE 3110-01-M

POSTAL RATE COMMISSION

[Docket No. MC79-3]

Red Tag Proceeding, 1979

July 13, 1979.

Notice is hereby given that pursuant to the "Presiding Officer's Notice Establishing Procedural Dates", dated July 12, 1979, the following schedule has been established to include certain procedural dates which were not set by the Commission in its Order Nos. 228 and 270, and its Notice of June 5, 1979:

Date and Procedural Stage

August 10, 1979—Completion of discovery directed to intervenors (including OOC).
September 10, 1979—Beginning of hearings.
September 18, 1979—Completion of evidentiary hearings as to cases-in-chief and Postal Service witnesses.
October 12, 1979—Filing of rebuttal evidence of all participants (including OOC and Postal Service)

All dates set in this Notice may be changed if the Commission decides to invite testimony on the subjects covered by its First Notice of Inquiry in this docket.

A tentative schedule for appearance of witnesses was also included in the Presiding Officer's Notice. A copy of the Presiding Officer's Notice is available to all interested parties in the Commission's Docket Room at the Postal Rate Commission, or by calling the Docket Room at Area Code 202-254-3800.

David F. Harris,
Secretary.

[FR Doc. 79-22596 Filed 7-20-79; 8:45 am]
BILLING CODE 7715-01-M

DEPARTMENT OF TRANSPORTATION

Federal Railroad Administration

[Docket No. RFA 505-79-3]

Purchase of Redeemable Preference Shares Receipt of Application

Project: Notice is hereby given that Indiana Harbor Belt Railroad Company (applicant), 2721 161st Street, Hammond, Indiana 46325, has filed an application with the Federal Railroad Administration (FRA) under section 505 of the Railroad Revitalization and Regulatory Reform Act of 1976, 45 U.S.C. 825, seeking financial assistance through the sale to the United States of redeemable preference shares (shares) in the yeard 1979 through 1983 having an aggregate par valuw of $31,164,500. Applicant proposes to redeem the par value of the shares and to pay dividends on the shares in accordance with a schedule such that payments will commence 11 years from the date of issuance of the shares and the par value of the shares will be redeemed within 30 years of their date of issuance.

The proceeds of the sale of the shares are to be used by the applicant to rehabilitate and improve its rail facilities and to rehabilitate 54 of its locomotives in accordance with the following schedule:

Project	Completion date	FRA funding (million)
Blue Island Yard:		
Rehabilitation	1983	$12.93
Construction of 6 tracks	1981	3.42
Locomotive Repair	1983	6.91
Centralized traffic control	1980	0.84
Signal rehabilitation	1980	0.25
Norpaul Yard:		
Rehabilitation	1981	0.33
Dolton connection	1979	0.05
Gibson shops:		
Rehabilitation	1980	1.09
Subtotal		25.82
Project management		.91
Contingencies		4.43
Total		31.16

Justification for project: Applicant states that the project will enable it to maintain and improve essential freight services in the Chicago area, will allow increased operating speeds and reduce accidents, and will expedite traffic flow over its properties.

Comments: Interested persons may submit written comments on the application to the Associate Administrator for Federal Assistance, Federal Railroad Administration, 400 Seventh Street SW., Washington, D.C. 20590, not later than the comment closing date shown below. Such submission should indicate that docket number shown on this notice and state whether the commenter supports or opposes the application and the reasons therefor.

To the extent permitted by law, the application will be made available for inspection during normal business hours in Room 5415 at the above address of the FRA in accordance with the regulations of the Office of the Secretary of Transportation set forth in Part 7 of Title 49 of the Code of Federal Regulations.

The comments will be considered by the FRA in evaluating the application. Any commenter who wishes to have FRA acknowledge the receipt of his or her comments should include a self-addressed, stamped post card with the comments. No other acknowledgment of comments will be provided.

The FRA has not approved or disapproved this application nor has it passed upon the accuracy or adequacy of the information contained therein.

(Sec. 505 of the Railroad Revitalization and Regulatory Reform Act of 1976 (Pub. L. 94-210), as amended.)

Dated: July 17, 1979.

Comment closing date: August 22, 1979.

Charles Swinburn,

Associate Administrator for Federal Assistance, Federal Railroad Administration.

[FR Doc. 79-22698 Filed 7-20-79; 8:45 am]

BILLING CODE 4910-06-M

[FRA Waiver Petition Docket HS-79-11]

Sierra Railroad Co.; Petition for Exemption From the Hours of Service Act

In accordance with 49 CFR Section 211.41 and Section 211.9, notice is hereby given that the Sierra Railroad Company (Sierra) has petitioned the Federal Railroad Administration (FRA) for an exemption from the Hours of Service Act (83 Stat. 464, Pub. L. 91-169, 45 U.S.C. 64a(e)). That petition requests that the Sierra be granted authority to permit certain employees to continuously remain on duty for in excess of twelve hours.

The Hours of Service Act currently makes it unlawful for a railroad to require or permit specified employees to continuously remain on duty for a period in excess of twelve hours. However, the Hours of Service Act contains a provision that permits a railroad, which employs no more than fifteen employees who are subject to the statute, to seek an exemption from this twelve hour limitation.

The Sierra seeks this exemption so that it can permit certain employees to remain continuously on duty for periods not to exceed sixteen hours. The petitioner indicates that granting this exemption is in the public interest and will not adversely affect safety. Additionally, the petitioner asserts that it employs no more than fifteen employees and has demonstrated good cause for granting this exemption.

Interested persons are invited to participate in this proceeding by submitting written views or comments. FRA has not scheduled an opportunity for oral comment since the facts do not appear to warrant it. Communications concerning this proceeding should identify the Docket Number, Docket Number HS-79-11, and must be submitted in triplicate to the Docket Clerk, Office of the Chief Counsel, Federal Railroad Administration, Trans Point Building, 2100 Second Street, S.W., Washington, D.C. 20590. Communications received before August 24, 1979, will be considered by the FRA before final action is taken. Comments received after that date will be considered as far as practicable. All comments received will be available for examination both before and after the closing date for comments, during regular business hours in Room 4406, Trans Point Building, 2100 Second Street, S.W., Washington, D.C. 20590.

Authority: Section 5 of the Hours of Service Act of 1969 (45 U.S.C. 64a), 1.49(d) of the regulations of the Office of the Secretary, 49 CFR 1.49(d).

Issued in Washington, D.C. on July 11, 1979.

J. W. Walsh,

Chairman, Railroad Safety Board.

[FR Doc. 79-22451 Filed 7-20-79; 8:45 am]

BILLING CODE 4910-06-M

Materials Transportation Bureau

Grants and Denials of Applications for Exemptions

AGENCY: Materials Transportation Bureau, DOT.

ACTION: Notice of Grants and Denials of Applications for Exemptions.

SUMMARY: In accordance with the procedures governing the application for, and the processing of, exemptions from the Department of Transportation's Hazardous Materials Regulations (49 CFR Part 107, Subpart B), notice is hereby given of the exemptions granted May 1979. The modes of transportation involved are identified by a number in the "Nature of Exemption Thereof" portion of the table below as follows: 1—Motor vehicle, 2—Rail freight, 3—Cargo-vessel, 4—Cargo-only aircraft, 5—Passenger-carrying aircraft. Application numbers prefixed by the letters EE represent applications for Emergency Exemptions.

Application No.	Number	Applicant	Regulation(s) affected	Nature of exemption thereof
		RENEWALS		
3390-X	DOT-E 3330	Teledyne Wah Chang, Albany Corp., Albany, Oreg.	49 CFR 173.214(d)	To ship flammable solid in insulated containers overpacked in a DOT specification 17C, 17H, or 37A metal drum. (Modes 1 and 2.)
3353-X	DOT-E 3353	Kerr-McGee Chemical Corp., Oklahoma City, Okla.	49 CFR 173.163(a)(7), 173.299(a)(2).	To ship a certain oxidizing material in a non-DOT specification steel or aluminum tank. (Modes 1 and 2.)
4177-X	DOT-E 4177	Hydrodyne Industries, Inc., Hauppauge, N.Y.	49 CFR 173.302(a)(1), 175.3	To ship a nonflammable, nonliquefied gas in a non-DOT specification pressure vessel. (Modes 1, 2, 3, and 4.)

Application No.	Number	Applicant	Regulation(s) affected	Nature of exemption thereof
		RENEWALS—Continued		
4760-X	DOT-E 4760	Gardner Cryogenics, Bethlehem, Pa.	49 CFR 172.101, 173.315(a)	To ship a nonflammable gas in a non-DOT specification cargo tank designed and constructed in accordance with the ASME Code. (Mode 1.)
5322-P	DOT-E 5322	LNG Services, Inc., Pittsburgh, Pa	49 CFR 172.101, 173.315(a)	To become a party to exemption 5322. (See Application No. 5322-P). (Mode 1.)
5403-X	DOT-E 5403	Halliburton Services, Duncan, Okla.	49 CFR parts 173; 178.343-2(b), 178.343-5(b)(1)(i), (b)(2)(i).	To ship certain corrosive materials in DOT specification MC-312 cargo tanks with certain exceptions. (Mode 1.)
5413-X	DOT-E 5413	Publicker Industries, Inc., Philadelphia, Pa.	49 CFR 172.101, 173.315(a)(1)	To ship a flammable gas in non-DOT specification cargo tanks designed and constructed in accordance with section VIII of the ASME Code.
5643-X	DOT-E 5643	Union Carbide Corp., Tarrytown, N.Y.	49 CFR 172.101, 173.315(a)(1)	To ship a nonflammable gas in a vacuum insulated non-DOT specification portable tank. (Modes 1 and 3.)
6443-X	DOT-E 6443	Montana Sulfur and Chemical Co., Billings, Mont.	49 CFR 173.315(a)(1), 172.504	To ship a flammable gas in DOT specification MC-331 insulated cargo tanks. (Mode 1.)
6500-X	DOT-E 6500	East Asiatic Co., Copenhagen, Denmark Blue Star Line, Ltd., London, England.	49 CFR 173.125	To ship a certain flammable liquid in a non-DOT specification stainless steel portable tank. (Modes 1 and 3.)
6517-X	DOT-E 6517	Coyne Cylinder Co., Huntsville, Ala.	49 CFR 173.303(a)	To provide for use of existing non-DOT specification steel cylinders for shipment of acetylene. (Modes 1, 2, and 3.)
6686-X	DOT-E 6686	Chilton Metal Products Division, Chilton, Wis.	49 CFR 173.304, 178.65	To ship a certain flammable gas in a modified DOT Specification 39 steel cylinder. (Modes 1 and 2.)
6720-X	DOT-E 6720	Sea-Land Service, Inc., Elizabeth, N.J.	46 CFR 90.05-35; 49 CFR parts 173.	To ship certain hazardous materials in non-DOT specification intermodal portable tanks. (Modes 1, 2, and 3.)
6752-X	DOT-E 6752	Pennwalt Corp., Philadelphia, Pa.	49 CFR 173.304(a)(2), 173.301(d)(3).	To ship a liquefied flammable compressed gas in DOT specification 3A2400 cylinders. (Mode 1.)
6762-P	DOT-E 6762	Taylor Chemicals, Inc., Baltimore, Md.	49 CFR 173.286(b)(2), 175.3	To become a party to Exemption 6762. (See application No. 6762-P.) (Modes 1, 2, and 4.)
6921-P	DOT-E 6921	Cities Service Co., Tulsa, Okla	49 CFR 172.101, 173.315(a)(1)	To become a party to Exemption 6921. (See application No. 6921-P.) (Modes 1 and 3.)
6969-X	DOT-E 6969	The State of Alaska, Juneau, Alaska.	14 CFR 121.574(a), 135.114(a); 49 CFR 175.85(a), (e).	To transport oxygen in DOT specification 3AA cylinders integral to incubators. (Mode 5.)
6984-X	DOT-E 6984	Powder River Explosives, Inc., Billings, Mont.	49 CFR 173.66(g), 173.103(a), 177.835(g)(2)(i).	To ship blasting caps, class C explosives in inside pasteboard cartons or tubes overpacked in an IME standard 22 container. (Mode 1.)
7015-P	DOT-E 7015	Jack B. Kelley, Inc., Amarillo, Tex.	49 CFR 173.315(a) (1), 172.101	To become a party to exemption 7015. (See application No. 7015-P.) (Modes 1, 2, and 3.)
7052-P	DOT-E 7052	Westinghouse Electric Corp., Raleigh, N.C.; Panasonic Co., Secaucus, N.J.	49 CFR 172.101, 173.206(e)(1), 175.3.	To become a party to exemption 7052. (See Application No. 7052-P.) (Modes 1, 2, 3, and 4.)
7056-X	DOT-E 7056	Diamond Shamrock Corp., Morristown, N.Y.	49 CFR 173.204(a)(4), 173.28(m).	To ship a certain flammable solid in DOT specification 37A275 steel drums. (Modes 1, 2, and 3.)
7066-X	DOT-E 7066	Compagnie des Containers Reservoirs, Paris, France.	49 CFR 173.119(m), 173.346	To ship certain flammable and class B poisonous liquids in non-DOT specification portable tanks. (Modes 1 and 3.)
7072-X	DOT-E 7072	Container Corp., of America, Wilmington, Del.	49 CFR part 173, subparts D, E, and F.	To manufacture, mark and sell non-DOT specification 55-gallon polyethylene containers for shipment of certain corrosive liquids, oxidizers, flammable liquids, poison B liquids, and liquid organic peroxides. (Modes 1, 2, and 3.)
7458-X	DOT-E 7458	Ekohwerks Co., Eastlake, Ohio	49 CFR 173.304(a)(2), 178.42	To manufacture, mark and sell non-DOT specification seamless cylinders for shipment of nonflammable gases. (Modes 1, 2, and 3.)
7567-X	DOT-E 7567	Conus, Inc., Jonesboro, Ark	49 CFR 172.101, 172.204(c)(3), 173.27, 175.30(a)(1), 175.320(b); 49 CFR part 107, appendix B.	To transport certain class A, B, and C explosives in cargo-only aircraft. (Mode 4.)
7822-X	DOT-E 7822	Air Products and Chemicals, Inc., Allentown, Pa.	49 CFR 172.101, 173.315(a)	To ship a nonflammable gas in specially insulated non-DOT specification portable tank designed and constructed in accordance with sections VIII and IX of the ASME Code. (Modes 1 and 3.)
7845-X	DOT-E 7845	Livingston Copters, Inc., Juneau, Alaska.	49 CFR 172.101, 175.3, 175.30(a)(1), 175.85(b).	To transport a flammable gas in DOT specification 4B240, 4BA240, and 4BW240 cylinders. (Mode 4.)
7865-X	DOT-E 7865	Applied Equipment Co., Van Nuys, Calif.	49 CFR 173.302(a)(4), 175.3, 178.65.	To manufacture, mark and sell welded, non-refillable non-DOT specification steel cylinders for shipment of nitrogen. (Modes 1 and 4.)
7887-P	DOT-E 7887	Flight Systems, Inc., Raytown, Mo.; Small Sounding Rocket Systems, Mountlake Terrace, Wash.; Composite Dynamics, North Las Vegas, Nev.	49 CFR part 107, 172.101, 173.111, 175.3.	To become a party to exemption 7887. (See application No. 7887-P.) (Modes 1, 2, 3, 4, and 5.)
7924-P	DOT-E 7924	Ray-O-Vac Div., ESB Inc., Madison, Wis.; Eagle-Picher Industries, Inc., Joplin, Mo.	49 CFR 173.206, 175.3	To become a party to exemption 7924. (See application No 7924-P.) (Modes 1, 2, 3, 4, and 5.)
7942-X	DOT-E 7942	Chevron U.S.A. Inc., San Francisco, Calif.	49 CFR 173.28(m)	To ship a flammable liquid in DOT specification 17E drums specially qualified for reuse. (Mode 3.)
8000-X	DOT-E 8000	Fauvet-Girel, Paris, France	49 CFR Part 173	To ship certain flammable, corrosive, irritating, class B poison, combustible liquids and organic peroxides in non-DOT specification portable tanks. (Modes 1, 2, and 3.)
8035-X	DOT-E 8035	NL McCullough, NL Industries, Inc., Houston, Tex.	49 CFR 173.100(v), 173.112, 175.3.	To ship a Class C explosive in plastic tubes snugly packed in a DOT specification 12B fiberboard box. (Modes 1, 2, 3, 4, and 5.)
8055-P	DOT-E 8055	American Cyanamid Co., Bound Brook, N.J.; Halstab Division, Hammond, Ind.	49 CFR 173.154	To become a party to exemption 8055. (See application No. 8055-P.) (Modes 1, 2, and 3.)
8118-X	DOT-E 8118	Magna Corp., Houston, Tex.	46 CFR 64.9; 49 CFR 173.119(b).	To ship certain flammable liquids in a marine portable tank. (Modes 1 and 3.)

Application No.	Number	Applicant	Regulation(s) affected	Nature of exemption thereof
		New Exemptions		
8039-N	DOT-E 8039	Chemwood International, Inc., Stamford, Conn.	49 CFR 173.245a	To ship a corrosive and poisonous B liquid in a DOT specification 51 portable tank. (Modes 1, 2, and 3.)
8062-N	DOT-E 8062	Hamill Manufacturing Co., Washington, Mich.	49 CFR 173.153, 173.154, 175.3	To ship a passive restraint system containing a mixture of a flammable solid and a class B explosive as a flammable solid in non-DOT specification fiberboard boxes. (Modes 1, 2, 3, and 4.)
8062-P	DOT-E 8062	Ford Motor Co., Dearborn, Mich	49 CFR 173.153, 173.154, 175.3	To become a party to exemption 8062. (See Application No. 8062-P.) (Modes 1, 2, 3, and 4.)
8113-N	DOT-E 8113	Turco Products, Carson, Calif.	49 CFR 173.245(a)(12)	To ship a corrosive material in a "F" style metal can overpacked in quantities of four in a DOT specification 12B corrugated fiberboard box. (Mode 1.)
8121-N	DOT-E 8121	Republic Steel Corp., Cleveland, Ohio.	49 CFR 173.245(a)	To ship a corrosive liquid in a DOT specification 57 portable tank. (Mode 1.)
8125-N	DOT-E 8125	Fauvet-Girel, Paris, France	49 CFR 173.123, 173.315	To ship certain flammable and nonflammable gases and flammable liquids in non-DOT specification non-insulated portable tanks. (Modes 1 and 3.)
8126-N	DOT-E 8126	Fauvet-Girel, Paris, France	49 CFR 173.123, 173.315	To ship certain liquefied petroleum gases and other gases classed as flammable gases and a flammable liquid in non-DOT specification portable tanks. (Modes 1 and 3.)
8166-N	DOT-E 8166	International Minerals & Chemical Corp., Mundelein, Ill.	49 CFR 173.154, 173.163	To ship an oxidizer in a DOT specification MC-306, MC-307, and MC-312 cargo tanks. (Mode 1.)
		Emergency Exemptions Applications Received and Granted		
EE8208-N	DOT-E 8208	Jet Propulsion Lab., Pasadena, Calif.	49 CFR 173.145, 173.278, 173.336.	To ship liquid propellant samples, frozen in non-DOT specification plywood boxes. (Mode 1.)
EE8216-N	DOT-E 8216	Connell Brothers Co., Ltd., San Francisco, Calif.	49 CFR 172.101, 175.30(a)(1)	To transport ammunition for cannon with explosive projectile via cargo-only aircraft. (Mode 4.)

Denials

7621-X—Request by Thomas and Sewell, Alexandria, Va.—For a 60-day extension of emergency examption for shipment of chloropicrin, liquid in a non-DOT specification portable tank, denied May 3, 1979.

7870-X—Request by Explogiochi, S.p.A., Florence, Italy—To ship toy caps packed in plastic blister packs, denied May 11, 1979 as being unnecessary.

EE8200-N—Request by Fleming International Airways, Inc., Miami, Fla.—For an emergency exemption to transport one shipment of certain Class A and Class C explosives comingled aboard the same aircraft, denied May 11, 1979.

Withdrawals

7690-X—Request by Prestex Products Co., St. Paul, Minn.—To ship certain flammable liquids in DOT Specification 34 polyethylene container, withdrawn May 24, 1979.

Douglas A. Crockett,

Chief, Standards Division, Office of Hazardous Materials Regulation, Materials Transportation Bureau.

[FR Doc. 79-22460 Filed 7-20-79; 8:45 am]

BILLING CODE 4910-60-M

National Highway Traffic Safety Administration

[Docket No. EX79-01; Notice 1]

Model A and Model T Motor Car Reproduction Corp.; Petition for Temporary Exemption From Federal Motor Vehicle Safety Standards

The Model A and Model T Motor Car Reproduction Corporation of Detroit, Michigan ("Model A" herein) has petitioned for a temporary exemption of three years of its Model A replica passenger car from certain safety standards on grounds of substantial economic hardship.

This notice of receipt of a petition for a temporary exemption is published in accordance with the NHTSA regulations on this subject (49 CFR 555.7), and does not represent any agency decision or other exercise of judgment concerning the merits of the petition.

Model A has not yet commenced manufacturing motor vehicles but has taken deposits on over 3,500 orders for a replica of a 1928 Ford Model A roadster. It "intends to produce only a limited number of these vehicles depending upon orders, and in all events, will limit production to below 10,000 vehicles over the three year exemption period." It therefore does not intend to achieve conformance with standards from which it is exempted.

The comany requests exemption from every safety standard applicable to passenger cars except Standards Nos. 101, 102, 106, 107, 111, 112, 113, 114, 115, 118, 124, 127, 205, 211, and 302. However, there will be partial compliance with some of the standards from which exemption is requested. Model A will provide two windshield wipers and a washer system as required by Standard No. 104, but its wiped pattern area will not meet the requirements of the standard. A brake warning light will be provided as required by Standard No. 105; while the braking system incorporates Ford Pinto and Ford Mustang components the petitioner believes that an exemption is necessary since it does not have the means to test for compliance. Its request for exemption from Standard No. 108 is limited to side marker lamps and reflectors which it believes are anachronistic to the vehicle. The tires and rims provided are of sizes not included in Standard Nos. 109 and 110. Model A has been asked to confirm that it will provide the tire inflation placard that the latter standard requires. A current model Ford Fairmont steering column will be used but the steering wheel design of the Model A "may not meet the standard." The fuel system uses Ford engine compartment components and a fuel tank of 14 gauge welded steel construction. A Type 1 seatbelt assembly will be provided at each designated seating position. The Company argues that to require compliance with many of the standards would cause hardship as it possesses no means with which to engage in expensive testing, and that if conformance is required the changes necessary to the vehicle design would be sufficient to destroy its character, and hence its sales appeal. In its first fiscal year ending March 31, 1979, Model A had a net loss of $109,000.

In support of its petition the company argues that it is not likely that its replica vehicles will present a significant hazard to traffic safety. It believes the overall concept is such that the vehicles' appeal primarily is for occasional, limited use (e.g., auto shows, resort use) rather than extensive daily use on the public roads.

Interested persons are invited to submit comments on the petition of Model A and Model T Motor Car Reproduction Corporation described above. Comments should refer to the docket number and be submitted to: Docket Section, National Highway Traffic Safety Administration, Room 5108, 400 Seventh Street SW., Washington, D.C. 20590. It is requested but not required that five copies be submitted.

All comments received before the close of business on the comment closing date indicated below will be considered. The application and supporting materials, and all comments received, are available for examination in the docket both before and after the closing date. Comments received after the closing date will also be filed and will be considered to the extent possible. Notice of final action on the petition will be published in the Federal Register pursuant to the authority indicated below.

Comment closing date: August 13, 1979.

(Sec. 3, Pub. L. 92-548, 86 Stat. 1159 (15 U.S.C. 1410); delegations of authority at 49 CFR 1.50 and 49 CFR 501.8)

Issued on July 18, 1979.

Michael M. Finkelstein,

Associate Administrator for Rulemaking.

[FR Doc. 79-22699 Filed 7-20-79; 8:45 am]

BILLING CODE 4910-59-M

DEPARTMENT OF THE TREASURY

Office of the Secretary

[Dept. Circular, Public Debt Series—No. 15-79]

Treasury Notes of July 31, 1981, Series V-1981

1. Invitation for Tenders

1. 1. The Secretary of the Treasury, under the authority of the Second Liberty Bond Act, as amended, invites tenders for approximately $3,000,000,000 of United States securities, designated Treasury Notes of July 31, 1981, Series V-1981 (CUSIP No. 912827 JU 7). The securities will be sold at auction with bidding on the basis of yield. Payment will be required at the price equivalent of the bid yield of each accepted tender. The interest rate on the securities and the price equivalent of each accepted bid will be determined in the manner described below. Additional amounts of these securities may be issued to Government accounts and Federal Reserve Banks for their own account in exchange for maturing Treasury securities. Additional amounts of the new securities may also be issued at the average price to Federal Reserve Banks, as agents for foreign and international monetary authorities, to the extent that the aggregate amount of tenders for such accounts exceeds the aggregate amount of maturing securities held by them.

2. Description of Securities

2. 1. The securities will be dated July 31, 1979, and will bear interest from that date, payable on a semiannual basis on January 31, 1980, and each subsequent 6 months on July 31 and January 31, until the principal becomes payable. They will mature July 31, 1981, and will not be subject to call for redemption prior to maturity.

2. 2. The income derived from the securities is subject to all taxes imposed under the Internal Revenue Code of 1954. The securities are subject to estate, inheritance, gift or other excise taxes, whether Federal or State, but are exempt from all taxation now or hereafter imposed on the principal or interest thereof by any State, any possession of the United States, or any local taxing authority.

2.3. The securities will be acceptable to secure deposits of public monies. They will not be acceptable in payment of taxes.

2.4. Bearer securities with interest coupons attached, and securities registered as to principal and interest, will be issued in denominations of $5,000, $10,000, $100,000, and $1,000,000. Book-entry securities will be available to eligible bidders in multiples of those amounts. Interchanges of securities of different denominations and of coupon, registered and book-entry securities, and the transfer of registered securities will be permitted.

2.5. The Department of the Treasury's general regulations governing United States securities apply to the securities offered in this circular. These general regulations include those currently in effect, as well as those that may be issued at a later date.

3. Sale Procedures

3.1. Tenders will be received at Federal Reserve Banks and Branches and at the Bureau of the Public Debt, Washington, D.C. 20226, up to 1:30 p.m., Eastern Daylight Saving time, Tuesday, July 24, 1979. Noncompetitive tenders as defined below will be considered timely if postmarked no later than Monday, July 23, 1979.

3.2. Each tender must state the face amount of securities bid for. The minimum bid is $5,000 and larger bids must be in multiples of that amount. Competitive tenders must also show the yield desired, expressed in terms of an annual yield with two decimals, e.g., 7.11%. Common fractions may not be used. Noncompetitive tenders must show the term "noncompetitive" on the tender form in lieu of a specified yield. No bidder may submit more than one noncompetitive tender and the amount may not exceed $1,000,000.

3.3. All bidders must certify that they have not made and will not make any agreements for the sale or purchase of any securities of this issue prior to the deadline established in Section 3.1. for receipt of tenders. Those authorized to submit tenders for the account of customers will be required to certify that such tenders are submitted under the same conditions, agreements, and certifications as tenders submitted directly by bidders for their own account.

3.4. Commercial banks, which for this purpose are defined as banks accepting demand deposits, and primary dealers, which for this purpose are defined as dealers who make primary markets in Government securities and report daily to the Federal Reserve Bank of New York their positions in and borrowings on such securities, may submit tenders for account of customers if the names of the customers and the amount for each customer are furnished. Others are only permitted to submit tenders for their own account.

3.5. Tenders will be received without deposit for their own account from commercial banks and other banking institutions; primary dealers, as defined above; Federally-insured savings and loan associations; States, and their political subdivisions or instrumentalities; public pension and retirement and other public funds; international organizations in which the United States holds membership; foreign central banks and foreign states; Federal Reserve Banks; and Government accounts. Tenders from others must be accompanied by a deposit of 5% of the fact amount of securities applied for (in the form of cash, maturing Treasury securities or readily collectible checks), or by a guarantee of such deposit by a commercial bank or a primary dealer.

3.6. Immediately after the closing hour, tenders will be opened, followed by a public announcement of the amount and yield range of accepted bids. Subject to the reservations expressed in Section 4, noncompetitive tenders will be accepted in full, and then competitive tenders will be accepted, starting with those at the lowest yields, through successively higher yields to the extent required to attain the amount offered. Tenders at the highest accepted yield will be prorated if necessary. After the determination is made as to which tenders are accepted, a coupon rate will be established, on the basis of a 1/8 of one percent increment, which results in an equivalent average accepted price close to 100.000 and a lowest accepted price above the original issue discount limit of 99.500. That rate of interest will be paid on all of the securities. Based on such interest rate, the price on each competitive tender allotted will be determined and each successful competitive bidder will be required to pay the price equivalent to the yield bid. Those submitting noncompetitive tenders will pay the price equivalent to the weighted average yield of accepted competitive tenders. Price calculations will be carried to three decimal places on the basis of price per hundred, e.g., 99.923, and the determinations of the Secretary of the Treasury shall be final. If the amount of noncompetitive tender received would absorb all or most of the offering, competitive tenders will be accepted in an amount sufficient to provide a fair determination of the yield. Tenders received from Government accounts and Federal Reserve Banks will be accepted at the price equivalent to the weighted average yield of accepted competitive tenders.

3.7. Competitive bidders will be advised of the acceptance or rejection of their tenders. Those submitting noncompetitive tenders will only be notified if the tender is not accepted in full, or when the price is over par.

4. Reservations

4.1. The Secretary of the Treasury expressly reserves the right to accept or reject any or all tenders in whole or in part, to allot more or less than the amount of securities specified in Section 1, and to make different percentage allotments to various classes of applicants when the Secretary considers it in the public interest. The Secretary's action under this Section is final.

5. Payment and Delivery

5.1. Settlement for allotted securities must be made or completed on or before Tuesday, July 31, 1979, at the Federal Reserve Bank or Branch or at the Bureau of the Public Debt, wherever the tender was submitted. Payment must be in cash; in other funds immediately available to the Treasury; in Treasury bills, notes or bonds (with all coupons detached) maturing on or before the settlement date but which are not overdue as defined in the general regulations governing United States securities; or by check drawn to the order of the institution to which the tender was submitted, which must be received at such institution no later than:

(a) Friday, July 27, 1979, if the check is drawn on a bank in the Federal Reserve District of the institution to which the check is submitted (the Fifth Federal Reserve District in case of the Bureau of the Public Debt), or

(b) Friday, July 27, 1979, if the check is drawn on a bank in another Federal Reserve District.

Checks received after the dates set forth in the preceding sentence will not be accepted unless they are payable at the applicable Federal Reserve Bank. Payment will not be considered complete where registered securities are requested if the appropriate identifying number as required on tax returns and other documents submitted to the Internal Revenue Service (an individual's social security number or an employer identification number) is not furnished. When payment is made in securities, a cash adjustment will be made to or required of the bidder for any difference between the face amount of securities presented and the amount payable on the securities allotted.

5.2. In every case where full payment is not completed on time, the deposit submitted with the tender, up to 5 percent of the face amount of securities allotted, shall, at the discretion of the Secretary of the Treasury, be forfeited to the United States.

5.3. Registered securities tendered as deposits and in payment for allotted securities are not required to be assigned if the new securities are to be registered in the same names and forms as appear in the registrations or assignments of the securities surrendered. When the new securities are to be registered in names and forms different from those in the inscriptions or assignments of the securities presented, the assignment should be to "The Secretary of the Treasury for (securities offered by this circular) in the name of (name and taxpayer identifying number)." If new securities in coupon form are desired, the assignment should be to "The Secretary of the Treasury for coupon (securities offered by this circular) to be delivered to (name and address)." Specific instructions for the issuance and delivery of the new securities, signed by the owner or authorized representative, must accompany the securities presented. Securities tendered in payment should be surrendered to the Federal Reserve Bank or Branch or to the Bureau of the Public Debt, Washington, D.C. 20226. The securities must be delivered at the expense and risk of the holder.

5.4. If bearer securities are not ready for delivery on the settlement date, purchasers may elect to receive interim certificates. These certificates shall be issued in bearer form and shall be exchangeable for definitive securities of this issue, when such securities are available, at any Federal Reserve Bank or Branch or at the Bureau of the Public Debt, Washington, D.C. 20226. The interim certificates must be returned at the risk and expense of the holder.

5.5. Delivery of securities in registered form will be made after requested form of registration has been validated, the registered interest account has been established, and the securities have been inscribed.

6. General Provisions

6.1. As fiscal agents of the United States, Federal Reserve Banks are authorized and requested to receive tenders, to make allotments as directed by the Secretary of the Treasury, to issue such notices as may be necessary, to receive payment for and make delivery of securities on full-paid allotments, and to issue interim certificates pending delivery of the definitive securities.

6.2. The Secretary of the Treasury may at any time issue supplemental or amendatory rules and regulations governing the offering. Public announcement of such changes will be promptly provided.

Supplementary Statement:

The announcement set forth above does not meet the Department's criteria for significant regulations and, accordingly, may be published without compliance with the Departmental procedures applicable to such regulations.

Paul H. Taylor,

Fiscal Assistant Secretary.

[FR Doc. 79-22672 Filed 7-20-79; 8:45 am]

BILLING CODE 4810-40-M

INTERSTATE COMMERCE COMMISSION

[Ex Parte No. 311]

Expedited Procedures for Recovery of Fuel Costs

Decided: July 17, 1979.

In our decisions of June 26, July 3, and July 10, 1979, a 7-percent surcharge was authorized on all owner-operator and truckload traffic. We ordered that all owner-operators were to receive compensation at this level. As indicated in the prior decisions, further upward changes were not contemplated until the Commission's weekly fuel index exceeded this 7-percent figure.

The weekly figures set forth in the appendix for transportation performed by owner-operators and truckload traffic is 7.2 percent. However, as stated in the June 26 decision, we recognize the concerns that have been expressed regarding the diesel fuel base price figure of 63.5 cents which did not include a factor for the lower prices associated with "self-service" utilized by many owner-operators during the base period. In addition, we are also aware of shipper concerns that weekly tariff adjustments are burdensome. As such, we are authorizing a 7.5 percent surcharge on all owner-operator and truckload traffic. All owner-operators are to receive compensation at this 7.5 percent level. As in the past, we will continue to publish the fuel index weekly. Further upward changes in the surcharge are not contemplated until the index exceeds 7.5 percent.

Further, for the reasons stated in the July 3 and July 10 decisions, no change will be made in the existing authorization of a 2.7 percent surcharge on less-than-truckload (LTL) traffic performed by carriers not utilizing owner-operators.

We have received many inquiries and complaints on problems of notice regarding our weekly orders. We will continue to study this matter and to provide additional notice if the fuel crisis lessens. In this instance, we will order that the decision shall become effective 12:01 a.m. July 18, 1979.

Notice of this decision shall be given to the general public by mailing a copy of this decision to the Governor of each state and to the Public Utilities Commissions or Boards of each State having jurisdiction over transportation, by deposting a copy in the Office of the Secretary, Interstate Commerce Commission, Washington, D.C., for public inspection, and by delivering a copy to the Director, Office of the Federal Register, for publication therein.

It is ordered:

This decision shall become effective 12:01 a.m., July 18, 1979.

By the Commission. Chairman O'Neal, Vice Chairman Brown, Commissioners Stafford, Gresham, Clapp and Christian. Vice Chairman Brown not participating.

Agatha L. Mergenovioh,

Secretary.

July 16, 1979.

Appendix.—*Fuel Surcharge*

Base Date and Price Per Gallon (Including Tax)

January 1, 1979 .... 63.5¢

Date of Current Price Measurement and Price Per Gallon (Including Tax)

July 16, 1979 .... 90.7¢

Average Percent: Fuel Expenses (Including Taxes) of Total Revenue

(1) From Transportation Performed by Owner Operators (Apply to All Truckload Traffic)	(2) Other (Including Less-Truckload Traffic)
16.9%	7.5%
Percent Surcharge	
7.2%	3.2%

[FR Doc. 79-22651 Filed 7-20-79; 8:45 am]

BILLING CODE 7035-01-M

[Notice No. 115]

Motor Carrier Temporary Authority Applications

June 28, 1979.

The following are notices of filing of applications for temporary authority under Section 210a(a) of the Interstate Commerce Act provided for under the provisions of 49 CFR 1131.3. These rules provide that an original and six (6) copies of protests to an application may be filed with the field official named in the Federal Register publication no later than the 15th calendar day after the date the notice of the filing of the application is published in the Federal Register. One copy of the protest must be served on the applicant, or its authorized representative, if any, and the protestant must certify that such service has been made. The protest must identify the operating authority upon which it is predicated, specifying the "MC" docket and "Sub" number and quoting the particular portion of authority upon which it relies. Also, the protestant shall specify the service it can and will provide and the amount and type of equipment it will make available for use in connection with the service contemplated by the TA application. The weight accorded a protest shall be governed by the completeness and pertinence of the protestant's information.

Except as othwise specifically noted, each applicant states that there will be no significant effect on the quality of the human environment resulting from approval of its application.

A copy of the application is on file, and can be examined at the Office of the Secretary, Interstate Commerce Commission, Washington, D.C., and also in the ICC Field Office to which protests are to be transmitted.

Note.—All applications seek authority to operate as a common carrier over irregular routes except as otherwise noted.

Motor Carriers of Property

MC 14215 (Sub-47TA), filed June 14, 1979. Applicant: SMITH TRUCK SERVICE, INC., 1118 Commercial, Mingo Junction, OH 43938. Representative: A. Charles Tell, 100 East Broad St., Columbus, OH. (1) *Building matrials and cement pipe containing asbestos fibre,* from the plantsite of Johns-Manville Sales Corp. at or near waukegan, IL, to points in OH; and (2) *insluation board,* from the plantsite of Johns-Manville Perlite Corp. at or near Rockdale, IL to points in OH, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Johns-

Manville Sales Corp., 2222 Kensington Court, Oak Brook, IL 60521. Send protests to: J. A. Niggemyer, DS, 416 Old P.O. Bldg., Wheeling, WV 26003.

MC 21455 (Sub-49TA), filed June 11, 1979. Applicant: GENE MITCHELL CO., West Liberty, IA 52776. Representative: Kenneth F. Dudley, P.O. Box 279, Ottumwa, IA 52501. *Wheat gluten and wheat products* from Keokuk, IA to Sacramento, San Francisco and Oakland, CA for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Campbell Taggart, Inc., P.O. Box 222640, Dallas, TX 75222. Send protests to: Herbert W. Allen, DS, ICC, 518 Federal Bldg., Des Moines, IA 50309.

MC 25255 (Sub-4TA), filed June 13, 1979. Applicant: LEE ROY HEERMAN d.b.a. COIN TRANSFER, P.O. Box 296, Coin, IA 51636. Representative: Lee Roy Heerman, same address as above. *General commodities, except those of unusual value, Class A and B explosives, livestock, household goods as defined by the Commission, commodities in bulk, and those requiring special equipment,* between Kansas City, MO and Kansas City, KS and their commercial zones, and Omaha, NE, on the one hand, and, on the other, points in IA on and west of IA Hwy 148, on and south of U.S. Hwy 34 and on and east of U.S. Hwy 59, for 180 days. An underlying ETA seeks 90 days authority. Applicant intends to tack this authority with authority in MC-25255 Subs 2 and 3. Applicant intends to interline with other carriers at Kansas City, MO; Kansas City, KS; and Omaha, NE. Supporting shipper(s): There are 6 statements in support attached to this application which may be examined at the ICC in Washington, D.C., or at the field office named below. Send protests to: Carroll Russell, ICC, Suite 620, 110d No. 14th St., Omaha, NE 68102.

MC 106674 (Sub-398TA), filed May 23, 1979. Applicant: SCHILLI MOTOR LINES, INC., P.O. Box 123, US Highway 24 West, Remington, IN 47977. Representative: Jerry L. Johnson (same address as applicant). *Stone, sand, and gravel in bags or boxes* from Louisville, KY and Bullitt County, KY to IL, IN, OH, MI, WI, MN, MS, MO, TN, GA, NC, SC, DC, MD, VA, NY, NJ, CT, IA, AL, PA, and WV for 180 days. Supporting shipper: Old Dutch Materials, 350 Pfingsten Road, North Brook, IL 60062. Send protests to: Beverly J. Williams, Transportation Assistant, ICC 46 E. Ohio St., Rm 429, Indianapolis, IN 46204. An underlying ETA seeks 90 days authority.

MC 107934 (Sub-30TA), filed June 19, 1979. Applicant: BYRD MOTOR LINE, INC., Hargrave Rd., Lexington, NC 27292. Representative: Melvin L. Byrd, Hargrave Road, Lexington, NC 27292. *Appliances (refrigerators, electric and gas ranges, freezers, air conditioners, automatic washers, dryers, dishwashers)* from Grand Rapids and Greenville, MI to Richmond, Altavista, Collinsville, Roanoke, VA and refused and damaged shipments from destination points to points of origin, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): E. A. Holstem, Inc., P.O. Box 26808, Richmond, VA 23261. Send protests to: Terrell Price, 800 Briar Creek Rd—Rm CC516, Charlotte, NC 28205.

MC 116915 (Sub-91TA), filed June 4, 1979. Applicant: ECK MILLER TRANSPORTATION CORPORATION, Route #1, P.O. Box 248, Rockport, IN 47635. Representative: Fred Bradley, P.O. Box 773, Frankfort, KY 40601. *Iron and steel articles* between the facilities of Maverick Tube Corporation at Union, MO, on the one hand, and, on the other, points in AR, TX, LA, OK, NC, SC, FL, TN, IL, OH, MI, and PA for 180 days. (Restricted to shipments originating at or destined to the facilities of Maverick Tube Corporation). Supporting shipper: Maverick Tube Corporation, P.O. Box 696, Union, MO 63084. Send protests to: Beverly J. Williams, Transportation Assistant, ICC, 46 E. Ohio Street, Rm 429, Indianapolis, IN 46204.

MC 116915 (Sub-92TA), filed June 4, 1979. Applicant: ECK MILLER TRANSPORTATION CORPORATION, Route #1, P.O. Box 248, Rockport, IN 47635. Representative: Fred Bradley, P.O. Box 773, Frankfort, KY 40610. *Aluminum and aluminum articles* between the facilities of Aluminum Company of America, located at Alcoa, TN, on the one hand, and, on the other, points in KY, IL, IN, MI, MO, and OH for 180 days. Supporting shipper: Aluminum Company of America, 1501 Alcoa Building, Pittsburgh, PA 15219. Send protests to: Beverly J. Williams, Transportation Assistant, ICC, 46 E. Ohio Street, Rm 429, Indianapolis, IN 46204.

MC 125254 (Sub-59TA), filed June 11, 1979. Applicant: MORGAN TRUCKING CO., 1201 E. 5th St., Muscatine, IA 52761. Representative: Larry D. Knox, 600 Hubbell Bldg., Des Moines, IA 50309. *Starch and dehydrated corn syrup (except commodities in bulk),* from Muscatine, IA to points in MO and MI for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Grain Processing Corporation, 1600 Oregon St., Muscatine, IA 52761. Send protests to: Herbert W. Allen, DS, ICC, 518 Federal Bldg., Des Moines, IA 50309.

MC 133095 (Sub-259TA), filed June 14, 1979. Applicant: TEXAS CONTINENTAL EXPRESS, INC., P.O. Box 434, Euless, TX 76039. Representative: Rocky Moore (same as applicant). *Meats, meat products and articles distributed by meat packinghouses (usual ICC description)* from Brownsville, TX to PA and NY Representative destinations: New Stanton, Pittsburgh, Philadelphia, and Scranton, PA; and NY, Brooklyn, Albany and Mt. Kisco, NY for 180 days. An underlying ETA seeking 90 days authority filed. Supporting shipper(s): Armour Fresh Meat Company, 111 W. Clarendon, Greyhound Tower, Phoenix, AZ. Send protests to: Martha A. Powell, Trans. Asst., I.C.C., Room 9A27 Fed. Bldg., 819 Taylor St., Forth Worth, TX 76102.

MC 133655 (Sub-162TA), filed June 14, 1979. Applicant: TRANS-NATIONAL TRUCK, INC., P.O. Box 31300, Amarillo, TX 79120. Representative: Warren L. Troupe, 2480 E. Commercial Blvd., Fort Lauderdale, FL 33308. *(1) Anti-freeze and fuel additives; and (2) equipment, materials, and supplies used in the manufacture and distribution of the commodities named in (1) above* between Weatherford, TX on the one hand, and, on the other, points in PA, KS, MO, OH, and CO for 180 days. An underlying ETA seeking 90 days authority filed. Supporting shipper(s): Power Service Products, Inc., P.O. Box 459, Weatherford, TX 76086. Send protests to: Martha A. Powell, Trans. Asst., I.C.C., Room 9A27 Fed. Bldg., 819 Taylor St., Fort Worth, TX 76102.

MC 133655 (Sub-163TA), filed June 14, 1979. Applicant: TRANS-NATIONAL TRUCK, INC., P.O. Box 31300, Amarillo, TX 79120. Representative: Warren L. Troupe, 2480 E. Commercial Blvd., Fort Lauderdale, FL 33308. *(1) Siding, clapboard, style, plastic item No. 170580, fittings, and accessories for installation; and (2) equipment, materials, and supplies used in the manufacture and distribution of the commodities named in (1) above* between Weatherford, TX on the one hand, and, on the other, points in OH, NY, MA and MD, for 180 days. An underlying ETA seeking 90 days authority filed. Supporting shipper(s): Robintech, 1202 N. Bowie Drive, Weatherford, TX 76086. Send protests to: Martha A. Powell, Trans. Asst., I.C.C., Room 9A27 Fed. Bldg., 819 Taylor St., Fort Worth, TX 76102.

MC 134405 (Sub-79TA), filed June 14, 1979. Applicant: BACON TRANSPORT COMPANY, P.O. Box 1134, Ardmore, OK 73401. Representative: Wilburn L. Williamson, Suite 615-East, The Oil Center, 2601 Northwest Expressway, Oklahoma City, OK 73401. *Asphalt*, in bulk, in tank vehicles, from North Kansas City, MO, to Sioux City, IA, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Trumbull Asphalt, A Division of Owens-Corning Fiberglas, 59th and Archer Road, Summit, IL 60501. Send protests to: Connie Stanley, ICC, Rm. 240, 215 N.W. 3rd, Oklahoma City, OK 73102.

MC 134755 (Sub-193TA), filed June 13, 1979. Applicant: CHARTER EXPRESS, INC., 1959 East Turner St., P.O. Box 3772, Springfield, MO 65804. Representative: Larry D. Knox, 600 Hubbell Bldg., Des Moines, IA 50409. *Frozen foodstuffs*, between Indianapolis, IN, on the one hand, and, on the other, points in AL, AR, CO, GA, KS, LA, MS, MO, OK, and TX, restricted to shipments originating at or destined to the facilities of Monument Distribution Warehouse, Inc., Indianapolis, IN, for 180 days. Supporting shipper(s): Monument Distribution Warehouse, Inc., 3320 S. Arlington Ave., Indianapolis, IN 46203. Send protests to: John V. Barry, DS, ICC, 600 Federal Bldg., 911 Walnut St., Kansas City, MO 64106.

MC 135364 (Sub-40TA), filed June 6, 1979. Applicant: MORWALL TRUCKING, INC., R.D. 3, Box 76C, Moscow, Pa 18444. Representative: J. G. Dail, Jr., P.O. Box LL, McLean, VA 22101. *Contract carrier*: irregular routes: *Such commodities as are manufactured, processed, sold, distributed, or dealt in by manufacturers and converters of paper and paper products (except commodities in bulk)*, between the facilities of the Paper, Printing, and Forms Group of Litton Business Systems, Inc., at Athens, OH, on the one hand, and on the other, the facilities of the Paper, Printing, and Forms Group of Litton Business Systems, Inc., located at or near Los Angeles, CA, Chicago, IL, Hasbrouck Heights, NJ, Farmingdale, NY, Ogden, UT, and Damascus, VA, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Paper, Printing, and Forms Group of Litton Business Systems, Inc., 601 River Street, Fitchburg, MA 01420. Send protests to: I.C.C., Fed. Res. Bank Bldg., 101 N. 7th St., Rm. 620, Phila., PA 19106.

MC 135454 (Sub-26TA), filed June 4, 1979. Applicant: DENNY TRUCK LINES, INC., 893 Ridge Road, Webster, NY 14580. Representative: Francis P. Barrett, Barrett and Barrett, 60 Adams Street, Milton, MA 02187. *Glass containers, closures for glass containers, and corrugated paper boxes and paper containers*, from the facilities of Anchor Hocking Glass Corporation at S. Connellsville, PA to points in Chautauqua County, NY, for 180 days. SUPPORTING SHIPPER: Anchor Hocking Glass Corporation, 109 N. Broad Street, Lancaster, PA 43130. SEND PROTESTS TO: Richard H. Cattadoris, DS, ICC, 910 Federal Bldg., 111 W. Huron Street, Buffalo, NY 14202. An underlying ETA seeks 90 days authority.

MC 136315 (Sub-80TA), filed June 19, 1979. Applicant: OLEN BURRAGE TRUCKING, INC., Rt. 9, Box 22-A, Philadelphia, MS 39350. Representative: Fred W. Johnson, Jr., P.O. Box 22628, Jackson, MS 39205. *Plywood and paneling* from the facilities owned or used by Pacific Wood Products Co. located in Orleans Parish, LA and Galveston County, TX to points in AR, GA, IL, IN, KS, KY, LA, MI, MN, MS, MO, NE, ND, OK, SD, TN, TX, WI, and AL, for 180 days. An underlying ETA 90 days authority. Supporting shipper(s): Pacific Wood Products Co., 22673 S. Wilmington Ave., Carson, CA 90745. Send protests to: Alan Tarrant, D/S, ICC, Rm. 212, 145 E. Amite Bldg., Jackson, MS 39201.

MC 133805 (Sub-28TA), filed June 14, 1979. Applicant: LONE STAR CARRIERS, INC., Rt. 1, Box 48, Tolar, TX 76476. Representative: Harry F. Horak, Suite 115, 5001 Brentwood Stair Road, Fort Worth, TX 76112. *Chemicals (except commodities in bulk) and materials and supplies used in the distribution thereof* from the facilities of Dow Chemical Company at or near Midland, MI to the facilities of McKesson Chemical Co. in OK and TX, and from the facilities of McKesson Chemical in TX to the facilities of McKesson Chemical Co. in OK for 180 days. An underlying ETA seeking 90 days authority filed. Supporting shipper(s): McKesson Chemical Company, 3525 N. Causeway Blvd., Jefferson Bank Bldg., Metairie, LA 70002. Send protests to: Martha A. Powell, Trans. Asst., I.C.C., Room 9A27 Fed. Bldg., 819 Taylor St., Fort Worth, TX 76102.

MC 133805 (Sub-29TA), filed June 14, 1979. Applicant: LONE STAR CARRIERS, INC., Rt. 1, Box 48, Tolar, TX 76476. Representative: Harry F. Horak, Suite 115, 5001 Brentwood Stair Road, Fort Worth, TX 76112. *Auto cleaner and polish in containers, and cardboard displays* from the TR-3 Chemical Corp. at or near Orange, CA to points in FL, TX, IL, UT, AR, OR, MA, WA, MI, LA, CO and AL for 180 days. An underlying ETA seeking 90 days authority filed. Supporting shipper(s): TR-3 Chemical Corp., 330 W. Taft Ave., Orange, CA 92667. Send protests to: Martha A. Powell, Trans. Asst., I.C.C., Room 9A27 Fed. Bldg., 819 Taylor St., Fort Worth, TX 76102.

MC 133805 (Sub-30TA), filed June 14, 1979. Applicant: LONE STAR CARRIERS, INC., Rt. 1, Box 48, Tolar, TX 76476. Representative: Harry F. Horak, Suite 115, 5001 Brentwood Stair Road. Fort Worth, TX 76112. *Stoneware, China, and steel flatware* between points in the U.S. (except AK and HI) for 180 days. An underlying ETA seeking 90 days authority filed. Supporting shipper(s): Wallace International, Inc., P.O. Box 22-226, Birmingham, AL 35228. Send protests to: Martha A. Powell, Trans. Asst., I.C.C., Room 9A27 Fed. Bldg., 819 Taylor St., Fort Worth, TX 76102.

MC 138824 (Sub-26TA), filed June 19, 1979. Applicant: REDWAY CARRIERS, INC., 5910 49th St., Kenosha, WI 53140. Representative: Paul Maton, 10 S. LaSalle St., Suite 1620, Chicago, IL 60603: Contract carrier; irregular routes; *Food products, dry or liquid, in containers; materials and supplies incidental to and used in the processing, canning and bottling of said food products*; restricted against transportation of commodities in bulk, between the facilities of Eau Claire packing Co., Eau Claire, MI on the one hand, and, on the other, points in WI, IL, IN, OH, Sulphur Springs, TX; Bordentown, NJ; Middleboro, MA; Northeast, PA; Lake Wales, FL and Montgomery, AL, for 180 days. An underlying ETA seeks 90 days authority.

MC 140615 (Sub-45TA), filed June 19, 1979. Applicant: DAIRYLAND TRANSPORT, INC., P.O. Box 1116, Wisconsin Rapids, WI 54494. Representative: Terrence Jones, 2033 K St., NW., Washington, DC 20006. *Liquid soap, ammonia, bleach, fabric softeners and detergents* from facilities of Manhattan Products, Inc. and Laundry Aids, Inc. at Carlstadt, NJ to Bedford, Cincinnati, Cleveland, Solon & Toledo, OH; Buffalo and Elmira, NY; Chicago, IL; Detroit, Grand Rapids & Livonia, MI; Ft. Wayne & Indianapolis, IN; Louisville, KY; and Pittsburgh, PA and to points in their commercial zones, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Manhattan Products, Inc. & Laundry Aids, Inc., 333 Starkes Rd., Carlstadt, NJ 07072. Send protests to: Gail Daugherty, TA, ICC, 517 E. Wisconsin Ave., Rm 619, Milwaukee, WI 53202.

MC 140744 (Sub-11TA), filed June 13, 1979. Applicant: ARCTIC AIR TRANSPORT, INC., 103 North Eau Claire Street, Mondovi, WI 54755. Representative: Stanly C. Olsen, Jr., 4601 Excelsior Boulevard, Minneapolis, MN 55416. *Meats, meat products, meat by-products and articles distributed by meat packing-houses (except hides and commodities in bulk) as described in Sections A, C and D of Appendix I to the report in Descriptions in Motor Carrier Certificates, 61 M.C.C. 209 and 766* between Britt and Mason City, IA, on the one hand, and, on the other, points in AL, AR, FL, GA, IL, IN, KY, LA, MI, MN, MS, MO, NE, NC, ND, OH, TN, SC, SD and WI, restricted to shipments originating at or destined to the facilities of Lauridsen Foods, Inc. at or near Britt, IA and Armour and Company at or near Mason City, IA, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Armour and Co., Greyhound Tower, Phoenix, AZ 85077. Send protests to: District Supervisor, ICC, 414 Federal Building & U.S. Court House, 110 South 4th Street, Minneapolis, MN 55401.

MC 141804 (Sub-236TA), filed June 13, 1979. Applicant: WESTERN EXPRESS, P.O. Box 3488, Ontario, CA 91761. Representative: Frederick J. Coffman, P.O. Box 3488, Ontario, CA 91761. *General commodities (except those of unusual value, Classes A & B explosives; household goods, as defined by the Commission, commodities in bulk, and commodities requiring special equipment)*, from points in NH, MA, ME, VT, and Willsboron, NY to points in AZ, CA, CO, NV, OR, UT, and WA. Restricted to the transportation of traffic originating at the facilities of New England shipping association co-operatives or at the facilities of its members originating at the named origins and destined to the indicated destinations, for 180 days. An underlying ETA seeks up to 90 days operating authority. Supporting shipper(s): New England Shipper's Association, 1029 Pearl Street, Brockton, MA 02401. Send protests to: Irene Carlos, T/A, I.C.C., P.O. Box 1551, Los Angeles, CA 90053.

MC 142114 (Sub-8TA), filed June 11, 1979. Applicant: RETAIL EXPRESS, INC., 9 Stuart Rd., Chelmsford, MA 01824. Representative: Frank M. Cushman Associates, 9 Stuart Rd., Chelmsford, MA 01824. *Contract carrier*: irregular routes: *Petroleum and Petroleum products, other than in bulk*, from points in the State of PA to points in the States of NY, NJ, CT, ME, MA, NH, RI and VT. Supporting shipper(s): John A. Wagner, Jr., T.M., Pennzoil Co., 106 Duncomb St., Oil City, PA. Send protests to: G. W. Flynn, TR&TS, Interstate Commerce Commission, 150 Causeway St., Boston, MA 02114.

MC 142364 (Sub-14TA), filed June 8, 1979. Applicant: KENNETH SAGELY, d.b.a. SAGELY PRODUCE COMPANY, 2802 Kibler Road, Van Buren, AR 72956. Representative: Don Garrison, P.O. Box 159, Rogers, AR 72756. Such merchandise as is dealt in by wholesale, retail and chain grocery and food business houses (except frozen commodities and commodities in bulk), from Houston, TX to points in AR, LA, MS and OK, restricted to the transportation of traffic originating at the facilities of Clorox Company, at or near Houston, TX, for 180 days. An underlying ETA seeks 90 days operating authority. Supporting shipper(s): The Clorox Company, 1221 Broadway Street, Oakland, CA 94612. Send protests to: William H. Land, Jr., District Supervisor, 3108 Federal Office Building, 700 West Capitol, Little Rock, AR 72201.

MC 142364 (Sub-15TA), filed June 13, 1979. Applicant: KENNETH SAGELY, d.b.a. SAGELY PRODUCE, 2802 Kibler Road, Van Buren, AR 72956. Representative: Don Garrison, P.O. Box 159, Rogers, AR 72756. *Foodstuffs* (except in bulk) from the facilities of American Home Foods, Inc., at or near La Porte, IN to points in AR, IL and MO, for 180 days. An underlying ETA seeks 90 days operating authority. Supporting shipper(s): American Home Foods, Inc., 685 Third Avenue, New York, NY 10017. Send protests to: William H. Land, Jr., District Supervisor, 3108 Federal Office Building, 700 West Capitol, Little Rock, AR 72201.

MC 144135 (Sub-1TA), filed June 1, 1979. Applicant: L & V TRUCKING, INC., 32650 Almaden Blvd., Union City, CA 94587. Representative: Engene Q. Carmody, 15523 Sedgeman St., San Leandro, CA 94579. (415) 357-6236. *Contract carrier*, irregular routes: *Vermiculite, other than crude: and gypsum wall plaster—in bags* between Newark, CA and Reno, Sparks, Carson City, South Lake Tahoe, North Lake Tahoe, NV, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Anning-Johnson Company, 1728 Gilbreth Rd., Burlingame, CA 94010. Send protests to: A. J. Rodriguez, 211 Main Street, Suite 500, San Francisco, CA 94105.

MC 145715 (Sub-7TA), filed June 12, 1979. Applicant: BELL TRUCKING, INC., 2504 Industrial Park Road, Van Buren, AR 72956. Representative: Bernard J. Kompare, Sullivan & Associates, Ltd., 10 South LaSalle Street, Suite 1600, Chicago, IL 60603. *Copper wire* from Canastota, NY to the facilities of Precision Cable Manufacturing Corporation, located at or near Garland, TX, restricted to the transportation of traffic originating at the above-named origin and destined to the above-named destinations, for 180 days. An underlying ETA seeks 90 days authority. Supporting Shipper(s): Precision Cable Manufacturing Corporation, 2722 National Place, Garland, TX 75040. Send protests to: William H. Land, Jr., District Supervisor, 3108 Federal Office Building, 700 West Capitol, Little Rock, AR 72201.

MC 147115 (Sub-1TA), filed May 15, 1979. Applicant: SCHALI TRANSPORT SYSTEMS, 5612 Hwy. 108, Oakdale, CA 95361. Representative: Robert Fuller, Suite 310, 13215 E. Penn St., Whittier, CA 90602. Chocolate or Cocoa Liquor, Cocoa Butter, Cocoa Beans and Cocoa Press or Kibble Cake in cartons, bags and blocks, from ports located in San Francisco and Alameda Counties, CA to Oakdale, CA for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper: Hershey Chocolate Company, 19 E. Chocolate Ave., Hershey, PA. SEND PROTESTS TO: N. C. Foster, 211 Main, Suite 500, San Francisco, CA 94105.

MC 147504 (Sub-1TA), filed May 23, 1979. Applicant: RSSI TRUCK LINE, INC., 2909 No. Emporia, Wichita, KS 67219. Representative: William B. Barker, 641 Harrison, Topeka, KS 66603. Contract carrier: irregular routes, (1) Asphalt and Roofing Materials, from facilities of Roofers Service Supply, Inc., Wichita, KS to points in AR, CO, IL, IN, IA, KY, MO, NE, NM, OK, TN and TX. (2) Materials and Supplies used in the manufacture and distribution of asphalt and roofing materials, in the reverse direction, under contract with Roofers Service Supply, Inc., Wichita, KS., for 180 days. Supporting Shipper(s): Roofers Service Supply, Inc., 2909 No. Emporia, Wichita, KS 67219. Send protests to: M. E. Taylor, D/S, 101 Litwin Bldg., Wichita, KS 67202.

MC 147585 (Sub-1TA), filed June 8, 1979. Applicant: DICK WELLER, INC., Shoham Road, P.O. Box 313, Warehouse Point, CT 06088. Representative: Thomas W. Murrett, 342 North Main Street, West Hartford, CT 06117. Common carrier: irregular routes, *(1) Electrical supplies: viz. raceways, conduit fittings and receptacles, cord sets, conduits, reels of insulated copper wire, wire moldings, and (2) flexible air distributing duct tubing*, from the facilities of the Wiremold Co. in West Hartford and Rocky Hill, CT to Atlanta, GA, Los Angeles, CA, Detroit, MI, and ports of entry at the U.S.-Canadian border at Erie and Niagara Counties, NY for 180 days. Supporting shipper(s): Wiremold Co., Woodlawn St., West Hartford, CT 06110. Send protests to: J. D. Perry, Jr., District Supervisor, I.C.C., 135 High Street, Hartford, CT.

MC 147405 (Sub-1TA), filed June 12, 1979. Applicant: C&C TRANSPORTATION, INC., 2501 Aztec NE., Albuquerque, NM 87107. Representative: Milton W. Flack, 4311 Wilshire Blvd., Suite 300, Los Angeles, CA 90010. *Contract carrier:* Irregular routes: *Vinyl floor covering and carpeting,* from Lancaster, Marietta and Marcus Hook, PA, and Salem, NJ, to the facilities of Standard Brands Paint Co., Inc., located at Torrance, CA, under a continuing contract(s) with Standard Brands Paint Co., Inc. of Torrance, CA, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Standard Brands Paint Co., Inc., 4300 West 190th Street, Torrance, CA 90509. Send protests to: DS/, ICC, 1106 Federal Office Building, 517 Gold Avenue SW., Albuquerque, NM 87101.

MC 147494 (Sub-1TA), filed June 11, 1979. Applicant: BOBBY KITCHENS, INC., P.O. Box 6161, Jackson, MS 39208. Representative: Fred W. Johnson, Jr., 1500 Deposit Guaranty Plaza, P.O. Box 22628, Jackson, MS 39205. *Bags, bagging material, carpet backing material and twine, and raw materials used in the manufacture and distribution of bags,* except in bulk, from Talladega, AL; Savannah, Nashville, Elberton, and Valdosta, GA; New Orleans and Crowley, LA; Charlotte and Hickory, NC; Spartanburg, SC: Memphis, TN; Houston, TX; and Front Royal, VA to points in CA, OR, TX and WA, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Friedman Bag Co., Inc., P.O. Box 3067, Terminal Annex, Los Angeles, CA 90051; Fisher Bag Co., 1560 First Ave., SO., Seattle, WA 98134. Send protests to: Alan C. Tarrant, D/S, ICC, Rm. 212, 145 E. Amite Bldg., Jackson, MS 39210.

MC 147245 (Sub-1TA), filed June 14, 1979. Applicant: GULICH TRUCKING, INC., Route 1, Roberts, WI 54023. Representative: Nancy Johnson, 103 E. Washington St., Crandon, WI 54520. *Crushed aggregate,* in dump vehicles, from Dresser, WI to Huntington, E. Gary, and Alexandria, IN: Detroit, MI: Earlham and Dubuque, IA; points in MN, N. Aurora, Chicago and its Commercial Zone, Moline and Northbrook, IL and Cameron, MO, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Bryan Dresser Trap Rock, Inc., Box 899, Minneapolis, MN 55440. Send protests to: Gail Daugherty, TA, ICC, 517 E. Wisconsin Ave., Rm. 619, Milwaukee, WI 53202.

MC 147415 (Sub-1TA), filed June 13, 1979. Applicant: SKY CORPORATION, P.O. Box 838, Bismarck, ND 58501. Representative: Charles E. Johnson, 418 East Rosser Avenue, Bismarck, ND 58501. *Sugar,* in bags, from the facilities of American Crystal Sugar Company near Moorhead, Crookston, and East Grand Forks, MN, to Bismark and Minot, ND, for 180 days. An underlying ETA seeks 90 days authority. Supporting Shipper(s): American Crystal Sugar Company, 101 North Third, Moorhead, MN 56560. Send protests to: H. E. Farsdale, DS, ICC, Bureau of Operations, Room 268 Fed. Bldg. & U.S. Post Office, 657 2nd Avenue North, Fargo, ND 58102.

MC 147515 (Sub-1TA), filed June 19, 1979. Applicant: CARSON PARKER, d.b.a. CLP ENTERPRISES, Cid Rd., Rt. Box 242-1AA, Denton, NC 27239. Representative: Terrell C. Clark, PO Box 25, Stanleytown, VA 24168. *Contract carrier*—Irregular routes: *(1) Empty containers* from Greensboro, Hickory, and High Point, NC to points in NC and *(2) new furniture* from points in NC to Greensboro, Hickory and High Point, NC, for 180 days. An underlying ETA seeks 90 days authority. Restricted to shipments having a prior or subsequent movement by rail. Supporting Shipper(s) Bloomingdale's of New York, 1000 Third Ave., New York, NY 10022. Send protests to: District Supervisor Terrell Price, 800 Briar Creek Rd., Rm CC516, Charlotte, NC 28205.

By the Commission.

H. G. Homme, Jr.,

Secretary.

[FR Doc. 79-22652 Filed 7-20-79; 8:45 am]

BILLING CODE 7035-01-M

Sunshine Act Meetings

Federal Register
Vol. 44, No. 142
Monday, July 23, 1979

This section of the FEDERAL REGISTER contains notices of meetings published under the "Government in the Sunshine Act" (Pub. L. 94-409) 5 U.S.C. 552b(e)(3).

CONTENTS

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[M-236, Amdt 3; July 18, 1979]

CIVIL AERONAUTICS BOARD.

Notice of Addition to the July 19, 1979, Meeting.

TIME AND DATE: 10 a.m., July 19, 1979.

PLACE: Room 1027, 1825 Connecticut Avenue, NW., Washington, D.C. 20428.

SUBJECT: 15a Dockets 32858, 33849, 34270, 34644, 35056, 35678, 35848, 35999, 36001, and 36106; Southeast Airlines—Information on existing exemption authority and consideration of pending applications for new exemption authority (BIA).

STATUS: Open.

PERSON TO CONTACT: Phyllis T. Kaylor, the Secretary, (202) 673-5068.

SUPPLEMENTARY INFORMATION: At the July 12 Board meeting, the Board decided to defer its decision on Southeast's certificate request in the Bahamas case, due to concerns about the carrier's request in the Bahamas case, due to concerns about the carrier's financial fitness. Because of these concerns, the public interest requires our immediate attention to Southeast's existing and pending exemption authority. Accordingly, the following members have voted that agency business requires that the Board meet on this item on less than seven days' notice and that no earlier announcement of this addition was possible.

Chairman, Marvin S. Cohen
Member, Richard J. O'Melia
Member, Elizabeth E. Bailey
Member, Gloria Schaffer

[S-1462-79 Filed 7-19-79; 3:15 pm]
BILLING CODE 6320-01-M

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COMMODITY FUTURES TRADING COMMISSION.

TIME AND DATE: 10 a.m., July 25, 1979.

PLACE: 2033 K Street NW., Washington, D.C., 8th floor conference room.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Judicial matters.

CONTACT PERSON FOR MORE INFORMATION: Jane Stuckey, 254-6314.

[S-1460-79 Filed 7-19-79; 3:57 pm]
BILLING CODE 6351-01-M

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FEDERAL DEPOSIT INSURANCE CORPORATION.

Notice of Changes in Subject Matter of Agency Meeting.

Pursuant to the provisions of subsection (e)(2) of the "Government in the Sunshine Act" (5 U.S.C. 552b(e)(2)), notice is hereby given that at its closed meeting held at 2:30 p.m. on Monday, July 16, 1979, the Corporation's Board of Directors determined, on motion of Chairman Irvine H. Sprague, seconded by Director William M. Isaac (Appointive), concurred in by Lewis G. Odom, Jr., acting in the place and stead of Director John G. Heimann (Comptroller of the Currency), that Corporation business required the withdrawal from the agenda for consideration at the meeting, on less than seven days' notice to the public, of a recommendation regarding the liquidation of assets acquired by the Corporation from American Bank & Trust Company, New York, New York (Case No. 43,972-SR).

The Board then determined, on motion of Chairman Sprague, seconded by Director Isaac, concurred in by Mr. Odom, that Corporation business required the addition of the following matters to the agenda for consideration at the meeting, on less than seven days' notice to the public:

Application of the Dime Savings Bank of New York, New York (Brooklyn), New York, an insured mutual savings bank, for consent to merge, under its charter and title, with Mechanics Exchange Savings Bank, Albany, New York, also an insured mutual savings bank, and for consent to establish the eight offices of Mechanics Exchange Savings Bank as branches of the resultant bank.

Memorandum and resolution proposing a delegation of authority to the Director of the Division of Bank Supervision to approve management official interlocks under section 348.4(3) of the Corporation's rules and regulations.

The Board further determined, by the same majority vote, that the public interest did not require consideration of the matters added to the agenda in a meeting open to public observation; that the matters could be considered in a closed meeting by authority of subsections (c)(8) and (c)(9)(A)(ii) of the "Government in the Sunshine Act" (5 U.S.C. 552b(c)(8) and (c)(9)(A)(ii)); and that no earlier notice of the changes in the subject matter of the meeting was practicable.

Dated: July 16, 1979.

Federal Deposit Insurance Corporation.
Hoyle L. Robinson,
Executive Secretary.

[S-1458-79 Filed 7-19-79; 11:17 am]
BILLING CODE 6714-01-M

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FEDERAL DEPOSIT INSURANCE CORPORATION.

Notice of Changes in Subject Matter of Agency Meeting.

Pursuant to the provisions of subsection (e)(2) of the "Government in the Sunshine Act" (5 U.S.C. 552b(e)(2)), notice is hereby given that at its open meeting held at 2:00 p.m. on Monday, July 16, 1979, the corporation's Board of Directors determined, on motion of Chairman Irvine H. Sprague, seconded by Director William M. Isaac (Appointive), concurred in by Mr. Lewis G. Odom, Jr., acting in the place and stead of Director John G. Heimann (Comptroller of the Currency), that Corporation business required the addition of the following matters to the agenda for consideration at the meeting, on less than seven days' notice to the public:

A memorandum and resolution proposing the final adoption of a new Part 344 of the

Corporation's rules and regulations, to be entitled "Recordkeeping and Confirmation Requirements for Securities Transactions."

A resolution expressing the Board's appreciation to Regional Director W. Harlan Sarsfield for his contributions in connection with the recent closings of two minority-owned Chicago banks.

A personnel journal appointing Mr. Frank Lloyd Skillern, Jr., as the Corporation's General Counsel.

The Board further determined, by the same majority vote, that no earlier notice of the changes in the subject matter of the meeting was practicable.

Dated: July 16, 1979.

Federal Deposit Insurance Corporation.

Hoyle L. Robinson,

Executive Secretary.

[S-1457-79 Filed 7-19-79; 11:17 am]

BILLING CODE 6714-01-M

5

FEDERAL ELECTION COMMISSION.

DATE AND TIME: Thursday, July 26, 1979, at 10 a.m.

PLACE: 1325 K Street NW., Washington, D.C.

STATUS: Portions of this meeting will be open to the public and portions will be closed.

MATTERS TO BE CONSIDERED:

Portions open to the public:

Setting of dates for future meetings.
Correction and approval of minutes.
Advisory opinions; AO 1979-32, Eugene R. Hoyer (Kanawha County Democratic Executive Committee). AO 1979-36, Wright H. Andrews (Committee for Fauntroy).
1980 election and related matters.
Use of advisory opinion procedure for past factual situations.
Filing requirements for non-candidate committees.
Appropriations and budget.
Pending legislation.
Classification actions.
Routine administrative matters.

Portions closed to the public (following Open Session): Compliance, Personnel.

PERSONS TO CONTACT FOR INFORMATION: Mr. Fred S. Eiland, Public Information Officer, Telephone: 202-523-4065.

Marjorie W. Emmons,

Secretary to the Commission.

[S-1465-79 Filed 7-19-79; 3:55 pm]

BILLING CODE 6715-01-M

6

July 18, 1979.

FEDERAL ENERGY REGULATORY COMMISSION.

TIME AND DATE: July 25, 1979, 10 a.m.

PLACE: 825 North Capitol Street NE., Washington, D.C. 20426, Room 9306.

STATUS: Open.

MATTERS TO BE CONSIDERED: Agenda.

Note.—Items listed on the agenda may be deleted without further notice.

CONTACT PERSON FOR MORE INFORMATION: Kenneth F. Plumb, Secretary, Telephone (202) 275-4166.

This is a list of matters to be considered by the Commission. It does not include a listing of all papers relevant to the items on the agenda; however, all public documents may be examined in the Office of Public Information.

Power Agenda—330th Meeting, July 25, 1979, Regular Meeting (10 a.m.)

CAP-1. Project No. 1855, New England Power Co.
CAP-2. Docket No. E-9601, Lake Oswego Corp.
CAP-3. Docket No. ER79-410, Puget Sound Power & Light Co.
CAP-4. Docket No. ER79-411, Central Hudson Gas and Electric Corp.
CAP-5. Docket No. ER79-407, Empire District Electric Co.
CAP-6. Docket No. ER78-315, Consolidated Edison Co. of New York
CAP-7. Docket No. ER79-402, Illinois Power Co.
CAP-8. Docket No. ER79-403, Illinois Power Co.
CAP-9. Docket No. ER79-426 and ER79-427, Florida Power & Light Co.
CAP-10. Docket No. ER79-388, Central Hudson Gas & Electric Corp., Consolidated Edison Co. and Niagara Mohawk Corp.
CAP-11. Docket No. ER78-402, Black Hills Power and Light Co.
CAP-12. Docket No. ER78-1, Kansas Power & Light Co.
CAP-13. Docket No. ER77-521, Arizona Public Service Co.
CAP-14. Docket No. ER78-103, Indiana & Michigan Electric Co.
CAP-15. Docket No. ER78-145, Arizona Public Service Co.
CAP-16. Docket No. ER78-499, Union Electric Co.
CAP-17. Docket No. ER78-417, Kentucky Utilities Co.
CAP-18. Docket No. ER78-425, Minnesota Power & Light Co.
CAP-19. Docket No. ER78-460 and ER78-483, Potomac Edison Co.
CAP-20. Docket No. ER79-21, Missouri Utilities Co.
CAP-21. Docket No. EL79-21, Ford Motor Credit Co., et al.

Miscellaneous Agenda—330th Meeting, July 25, 1979, Regular Meeting

CAM-1. Public Service Co. of Colorado
CAM-2. Docket No. RM79- , Publication of Prescribed Maximum Lawful Prices Under the Natural Gas Policy Act of 1978
CAM-3. Docket No. RO79-5, Exxon Co. U.S.A.

Gas Agenda—330th Meeting, July 25, 1979, Regular Meeting

CAG-1. Docket No. RP72-156 (PGA No. 79-2) (DCA No. 79-2), Texas Gas Transmission Corp.
CAG-2. Docket No. RP78-58 (PGA No. 79-2A), South Texas Natural Gas Gathering Co.
CAG-3. Docket No. RP73-65, Columbia Gas Transmission Corp.
CAG-4. Docket Nos. RP76-15 and RP76-98, Algonquin Gas Transmission Co.
CAG-5. Docket No. RP73-43 (PGA Nos. 79-2 and TT 79-3), Mid-Louisiana Gas Co.
CAG-6. Docket No. RP75-105, Columbia Gulf Transmission Co., Docket No. RP75-106 (Consolidated Taxes), Columbia Gas Transmission Corp.
CAG-7. Docket No. CI78-748, Atlantic Richfield Co., Docket No. CI78-924, Atlantic Richfield Co., Docket No. CI78-887, Northwest Exploration Co.
CAG-8. Docket Nos. CI78-180, et al., Texaco Inc.
CAG-9. Docket No. CI78-457, Terra Resources, Inc. (Successor in interest to Farmland International Energy Co.)
CAG-10. Docket No. CP78-416, Northern Natural Gas Co., Southern Natural Gas Co. and United Gas Pipeline Co.
CAG-11. Docket No. CP78-136, Transcontinental Gas Pipe Line Corp.
CAG-12. Docket No. CP79-171, Sea Robin Pipeline Co., Docket No. CP79-172, Florida Gas Transmission Co.
CAG-13. Docket No. CP79-326, Transwestern Pipeline Co. and Cities Service Gas Co.
CAG-14. Docket No. CP79-236, Gulf Energy & Development Corp., Docket No. CP79-237, Zapata Gathering Co.
CAG-15. Docket No. CP79-215, Texas Gas Transmission Corp.

Power Agenda—330th Meeting, July 25, 1979, Regular Meeting

I. Licensed Project Matters

P-1. Docket No. E-9530, *Pyramid Lake Paiute Tribe of Indians,* Complainant, v. *Sierra Pacific Power Company,* Respondent, Truckee-Carson Irrigation District and Washoe County Water Conservation District, Additional Respondent
P-2. Project No. 2216, Power Authority of the State of New York
P-3. Project No. 271, Arkansas Power & Light Co.

II. Electric Rate Matters

ER-1. Docket No. ER79-339, Arkansas Power & Light Co.
ER-2. Docket No. ER79-416, Florida Power & Light Co.
ER-3. Docket Nos. ER79-149 and E-9537, Public Service Co. of Indiana
ER-4. Docket No. E-9181, New England Power Co.
ER-5. Docket No. ER76-205, Southern California Edison Co.

Miscellaneous Agenda—330th Meeting, July 25, 1979, Regular Meeting

M-1. Docket No. RM79- , filing of change in rate schedules—revised section 35.13; preparation and submission of data for

electric cost of service program—new FERC Form No. 61.
M-2. Docket No. RM79-6, procedures governing the collection and reporting of information associated with the cost of providing electric service.
M-3. Reserved.
M-4. Reserved.
M-5. Docket No. RM79-3, interim regulations implementing the Natural Gas Policy Act of 1978.
M-6. Docket No. RM79- , withdrawal of notice of determination.
M-7. Docket No. RM79-8, final rule prescribing 15 year minimum duration for new contracts for some sales of certain OCS gas.
M-8. Notices of preliminary findings.
M-9. Docket Nos. OR79-1, I&S-9089, IS79-4, FS79-1, and FS79-2, Williams Pipe Line Co.

Gas Agenda—330th Meeting, July 25, 1979, Regular Meeting

I. Pipeline Rate Matters

RP-1. Docket No. RP74-41 (PGA No. 79-3 and DCA No. 79-2), Texas Eastern Transmission Corp.
RP-2. Docket No. RP72-32 (PGA79-1a) and RP79-8, Kansas-Nebraska Natural Gas Co., Inc.
RP-3. Docket Nos. RP72-142, RP76-135, and RP78-76 (PGA 79-2) (AP79-2), Cities Service Gas Co.
RP-4 (A) Docket Nos. RP71-107 (phase II) and RP72-127, Northern Natural Gas Co. (B) Docket No. RP76-49, show case proceeding in re pre-order 499 Alaskan advances.
RP-5. Docket Nos. RP76-96, RP77-57, and RP77-14, National Fuel Gas Supply Corp.
RP-6. Docket No. RP75-30, United Gas Pipe Line Co.
RP-7. Docket No. RP78-56, Northern Natural Gas Co.
RP-8. Docket No. RP78-58, South Texas Natural Gas Gathering Co.

II. Pipeline Certificate Matters

CP-1. Docket No. CP79-319, Consolidated Gas Supply Corp.
CP-2. Docket No. CP79-253, New Jersey Zinc Division of G&W Natural Resources Group, a division of Gulf & Western Industries, Inc.
CP-3. Docket Nos. CP75-358 and CP76-284, Tennessee Gas Pipeline Co., a division of Tenneco Inc.
CP-4. Docket No. RP76-147, Southern Natural Gas Co. (Delta-Macon Brick and Tile Co.).
CP-5. Docket No. RP72-99, Transcontinental Gas Pipe Line Co.

Kenneth F. Plumb,
Secretary.

[S-1460-79 Filed 7-19-79; 3:15 pm]
BILLING CODE 6450-01-M

7

FEDERAL HOME LOAN BANK BOARD.

TIME AND DATE: 9:30 a.m., July 26, 1979.

PLACE: 1700 G Street NW., Sixth Floor, Washington, D.C.

STATUS: Open Meeting.

CONTACT PERSON FOR MORE INFORMATION: Franklin O. Bolling, (202-377-6677).

MATTERS TO BE CONSIDERED:

Branch Office Application—Valley Federal Savings and Loan Association, Van Nuys, California.

Voluntary Termination of Insurance of Accounts and Withdrawal From Bank Membership—Spindale Savings and Loan Association, Spindale, North Carolina.

Application for Bank Membership—Warren Five Cents Savings Bank, Peabody, Masssachusetts.

Application for Bank Membership and Insurance of Accounts—Slovenian Savings and Loan Association of Franklin-Conemaugh (Mutual), Conemaugh, Pennsylvania.

Preliminary Application for Conversion to a Federal Mutual Charter—United Savings and Loan Association, Mount Airy, North Carolina.

Conversion From a Federal Savings and Loan Asssociation to a Mutual Savings Bank—Bellingham First Federal Savings and Loan Association, Bellingham, Washington.

Application for Permission to Convert to a Federal Chartered Stock Association—Home Federal Savings and Loan Association of Palm Beach, Palm Beach, Florida.

Board Resolution Leases.

Permission to Organize a New Federal Association—William R. Leary, et al., Houma, Louisiana.

Application for Permission to Convert to a Federal Chartered Stock Association Palmetto Federal Savings and Loan Association, Palmetto, Florida.

Amendment to Mobile Home Loans Regulation.

Regulation to Authorize Securing of Eurodollar Deposits.

Regulation Concerning Supervisory Authority.

No. 253, July 19, 1979.

[S-1463-79 Filed 7-19-79; 3:15 p.m.]
BILLING CODE 6720-01-M

8

FEDERAL RESERVE SYSTEM.

TIME AND DATE: 12:30 p.m., Wednesday, July 18, 1979 (Note: Following a recess, the open meeting commenced at 2 p.m. as previously announced). The business of the Board required that this meeting be held with less than one week's advance notice to the public, and no earlier announcement of the meeting was practicable.

PLACE: 20th Street and Constitution Avenue NW., Washington, D.C. 20551.

STATUS: Closed.

MATTER CONSIDERED: Federal Reserve Board officer compensation program. (This matter was originally announced for a meeting on Friday, July 20, 1979.)

CONTACT PERSON FOR MORE INFORMATION: Mr. Joseph R. Coyne, Assistant to the Board, (202) 452-3204.

Dated: July 18, 1979.

Griffith L. Garwood,
Deputy Secretary of the Board.

[S-1459-79 Filed 7-19-79; 3:15 pm]
BILLING CODE 6210-01-M

9

NATIONAL LABOR RELATIONS BOARD.

TIME AND DATE: 4 p.m., Wednesday, July 18, 1979.

PLACE: Board Conference Room, Sixth Floor, 1717 Pennsylvania Avenue NW., Washington, D.C. 20570.

STATUS: Closed to public observation.

MATTER TO BE CONSIDERED: Selection of Officer-in-Charge for Hartford, Connecticut subregion.

CONTACT PERSON FOR MORE INFORMATION: William A. Lubbers, Executive Secretary, Washington, D.C. 20570, Telephone: (202) 254-9430.

Dated: Washington, D.C., July 18, 1979.

By direction of the Board.

George A. Leet,
Associate Executive Secretary, National Labor Relations Board.

[S-1455-79 Filed 7-19-79; 11:17 am]
BILLING CODE 7545-01-M

10

NATIONAL NEIGHBORHOOD REINVESTMENT CORPORATION.

Meeting of the Board of Directors.

Pursuant to the Provisions of the Neighborhood Reinvestment Corporation Act (Title VI of the Housing and Community Development Amendments of 1978, P.L. 95-557), notice is hereby given of a meeting of the National Neighborhood Reinvestment Corporation.

TIME AND DATE: 2 p.m.; July 25, 1979.

PLACE: Board Room, Sixth Floor, 1700 G Street NW., Washington, D.C.

STATUS: Open Meeting, Board of Directors.

CONTACT PERSON FOR MORE INFORMATION: Donnie L. Bryant, 202-377-6480.

Agenda.—Call to Order and Remarks of Chairman—

Approval of Minutes—April 25, 1979 Meeting.
Executive Director's Report.
Selection of General Counsel.
Audit Committee Report.
Resolution: Investment of Corporate Funds.
Resolution: Authority for Budget Reallocation.
Resolution: Selection of Auditing Firm.

Personnel Committee Report—
Resolution: Selection of Retirement Fund.
Treasurer's Report.
No. 5, July 18, 1979.

Donnie L. Bryant,
Secretary.

[S-1454-79 Filed 7-19-79; 11:17 am]
BILLING CODE 6720-01-M

11

UNITED STATES PAROLE COMMISSION: National Commissioners (the Commissioners presently maintaining offices at Washington, D.C. Headquarters).

TIME AND DATE: Wednesday, July 25, 1979, at 10 a.m.

PLACE: Room 828, 320 First Street, NW., Washington, D.C. 20537.

STATUS: Closed pursuant to a vote to be taken at the beginning of the meeting.

MATTER TO BE CONSIDERED: Referrals from Regional Commissiners of approximately 15 cases in which inmates of Federal prisons have applied for parole or are contesting revocation of parole or mandatory release.

CONTACT PERSON FOR MORE INFORMATION: A. Ronald Peterson, Analyst: (202) 724-3094.

[S-1401-79 Filed 7-19-79; 3:15 pm]
BILLING CODE 4410-01-M

12

SECURITIES AND EXCHANGE COMMISSION.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: [44 FR 41020 July 13, 1979].

STATUS: Closed meeting.

PLACE: Room 825, 500 North Capitol Street, Washington, D.C.

DATE PREVIOUSLY ANNOUNCED: Tuesday, July 10, 1979

CHANGES IN MEETING: Additional item.

The following additional item will be considered at a closed meeting scheduled for Thursday, July 19, 1979, following the 10 a.m. open meeting:

Litigation matter.

Commissioners Loomis, Pollack and Karmel determined that Commission business required the above change and that no earlier notice thereof was possible.

At times changes in Commission priorities require alterations in the scheduling or meeting items. For further information and to ascertain what, if any, matters have been added, deleted or postponed, please contact: Beverly Rubman at (202) 755-1103.

July 18, 1979.

[S-1456-79 Filed 7-19-79; 11:17 am]
BILLING CODE 8010-01-M

13

[Meeting No. 1223]

TENNESSEE VALLEY AUTHORITY.

TIME AND DATE: 9:30 a.m., Thursday, July 26, 1979.

PLACE: Conference Room B-32, West Tower, 400 Commerce Avenue, Knoxville, Tennessee.

STATUS: Open.

MATTERS FOR ACTION:

PERSONNEL ACTIONS:

1. Change of status for William V. Pace from Manager of Minority Economic Development Program to Assistant Director of Commerce, Office of Community Development.[1]
2. Status changes relating to reorganization of Power Operations, Office of Power, Chattanooga, Tennessee.[1]
3. Status changes relating to staffing of key positions in the Office of Health and Safety.[1]

CONSULTING AND PERSONAL SERVICES CONTRACTS:

1. Renewal of consulting contract with Gordon F. Palm & Associates, Inc., Lakeland, Florida, for advice and assistance in connection with studies relating to the production of wet-process phosphoric acid, requested by the Office of Agricultural and Chemical Development.
2. Renewal of consulting contract with John M. Kellberg, Knoxville, Tennessee, for advice and assistance in connection with design and construction of hydro and thermal power plants, requested by the Office of Engineering Design and Construction.
3. Renewal of consulting contract with Francis B. Slichter, Annandale, Virginia, for advice and assistance in connection with design and construction of hydro projects, requested by the Office of Engineering Design and Construction.
4. Renewal of consulting contract with Roy W. Carlson, Berkeley, California, for advice and assistance in the field of concrete dam construction and inspection, requested by the Office of Engineering Design and Construction.
5. Renewal of consulting contract with Dr. Geno Saccomanno, Grand Junction, Colorado, for services in connection with environmental and safety aspects of the effects of nuclear power plants, requested by the Division of Occupational Health and Safety.
6. Consulting contract with Jack E. Gilleland, Signal Mountain, Tennessee, for advice and assistance in connection with TVA's power and energy-related programs, requested by the Office of Power.
7. Renewal of consulting contract with John T. Boyd Company, Pittsburgh, Pennsylvania, for advice and assistance in connection with TVA's coal supply, requested by the Office of Power.
8. Contract with Coopers & Lybrand, New York, New York, for audit of TVA's financial statements for fiscal year 1979, requested by the Division of Finance.

[1] These items were approved by individual Board members. This would give formal ratification to the Board's action.

PURCHASE AWARDS:

1. Req. No. 577543 (Reissue)—Indefinite quantity term contract for hot rolled steel bars and small shapes for any TVA nuclear project or warehouse.
2. Req. No. 823215—Major portion of plant principal piping systems for Yellow Creek Nuclear Plant.
3. Req. No. 825342—Insulated conductors, types PXJ and PXMJ, for Hartsville and Phipps Bend Nuclear Plants.

PROJECT AUTHORIZATIONS:

1. No. 3451—Addition to the bulk solid fertilizer storage building at the National Fertilizer Development Center.
2. No. 3361.2—Amendment to project authorization for railroad tank car replacements for TVA's tank car fleet used for shipping experimental TVA fertilizer.

POWER ITEMS:

1. New power contract with city of McMinnville, Tennessee.
2. New power contract with city of Gallatin, Tennessee.
3. New power contract with city of Harriman, Tennessee.
4. Memorandum governing power supply to Office of Agricultural and Chemical Development at Wilson Dam.
5. Letter agreement with Electric Board of Guntersville, Alabama, amending lease-purchase agreement to provide for purchase of approximately 2.35-mile section of TVA's Guntersville Dam No. 2-Albertville Primary 46-kV Line; and bill of sale and quitclaim deed conveying the section of line.
6. Policy statement relating to contract demand reductions for commercial and industrial customers to encourage adoption of conservation and load management techniques.
7. Agreement with Lakeland Retirement Community, Inc., covering arrangements for cooperation in construction and evaluation of multiresident retirement complex in Marshall County, Kentucky, which will demonstrate energy conserving concepts.

REAL PROPERTY TRANSACTIONS:

1. Filing of condemnation suits.

UNCLASSIFIED:

1. Settlement of litigation brought by Ralph L. Lankford and wife, Peggy Lankford, against TVA and its employee, Ralph Maples, as the result of an automobile accident.
2. Revised TVA policy code relating to selection for appointment, promotion, transfer, and retention of employees.
3. Amendment to agreement with Department of Housing and Urban Development for flood insurance studies.

CONTACT PERSON FOR MORE INFORMATION: James L. Bentley, Director of Information, or a member of his staff can respond to requests for information about this meeting. Call (615) 632-3257, Knoxville, Tennessee. Information is also available at TVA's Washington Office (202) 245-0101.

Dated: July 19, 1979.

[S-1464-79 Filed 7-19-79; 3:55 pm]

BILLING CODE 8120-01-M

federal register

Monday
July 23, 1979

Part II

Environmental Protection Agency

Stationary Internal Combustion Engines; Standards of Performance for New Stationary Sources and Addition to the List of Categories of Stationary Sources

ENVIRONMENTAL PROTECTION AGENCY

[FRL 1099-5]

[40 CFR Part 60]

Stationary Internal Combustion Engines; Standards of Performance for New Stationary Sources

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The proposed standards, which would apply to facilities that commence construction 30 months after today's date, would limit emissions of nitrogen oxides (NO_x) from new, modified, and reconstructed stationary gas, diesel, and dual-fuel internal combustion (IC) engines to 700 parts per million (ppm), 600 ppm, 600 ppm, respectively at 15 percent oxygen (O_2) on a dry basis. A revision to Reference Method 20 for determining the concentration of nitrogen oxides and oxygen in the exhaust gases from large stationary IC engines is also proposed.

The standards implement the Clean Air Act and are based on the Administrator's determination that stationary IC engines contribute significantly to air pollution. The intent is to require new, modified, and reconstructed stationary IC engines to use the best demonstrated system of continuous emission reduction, considering costs, non-air quality health, and environmental and energy impacts.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments.* Comments must be received on or before September 21, 1979.

Public Hearing. The public hearing will be held on August 22, 1979 beginning at 9:30 a.m. and ending at 4:30 p.m.

Request to Speak at Hearing. Persons wishing to attend the hearing or present oral testimony should contact EPA by August 15, 1979.

ADDRESSES: *Comments.* Comments should be submitted to Mr. Jack R. Farmer, Chief, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

Public Hearing. The public hearing will be held at the Environmental Research Center Auditorium, Room B101, Research Triangle Park, N.C. 27711. Persons wishing to attend or present oral testimony should notify Mary Jane Clark, Emission Standards and Engineering Divison (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

Standards Support Document. The support document for the proposed standards may be obtained from the EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Standards Support and Environmental Impact Statement: Proposed Standards of Performance for Stationary Internal Combustion Engines," EPA-450/3-78-125a.

Docket. The Docket, number OAQPS-79-5, is available for public inspection and copying at the EPA's Central Docket Section, Room 2903 B, Waterside Mall, Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Proposed Standards

The proposed standards, which are summarized in Table A, would apply to all new, modified, and reconstructed stationary internal combustion engines as follows:

1. Diesel and dual-fuel engines greater than 560 cubic inch displacement per cylinder (CID/cyl).
2. Gas engines greater than 350 cubic inch displacement per cylinder (CID/cyl) or equal to or greater than eight cylinders and greater than 240 cubic inch displacement per cylinder (CID/cyl).
3. Rotary engines greater than 1500 cubic inch displacement per rotor.

The proposed standards, which would go into effect 30 months after the date of proposal (i.e., today's date), would limit the concentration of NO_x in the exhaust gases from stationary gas, diesel and dual-fuel IC engines to 0.0700 percent by volume (700 ppm), 0.600 percent by volume (600 ppm), and 0.0600 percent by volume 600 ppm, respectively, at 15 percent oxygen (O_2) on a dry basis. These emission limits are adjusted upward linearly for IC engines with thermal efficiencies greater than 35 percent.

Table A.—*Summary of Internal Combustion Engine New Source Performance Standard*

Internal combustion engine size and fuel type	NO_x emission limit* (ppm)	Applicability date
Diesel Engines > 560 CID/cyl or > 1500 CID/rotor	600	30 months from date of proposal (i.e., today's date)
Dual-Fuel Engines > 560 CID/cyl or > 1500 CID/rotor	600	30 months from date of proposal (i.e., today's date)
Gas Engines > 350 CID/cyl or ≥ 8 cylinders *and* > 240 CID/cyl or 1500 > CID/rotor.	700	30 months from date of proposal (i.e., today's date)

*NO_x emission limit adjusted upward for internal combustion engines with thermal efficiencies greater than 35 percent. Measured NO_x emissions adjusted to standard atmospheric conditions of 101.3 Kilopascals (29.92 inches mercury), 29.4 degrees Centigrade (85 degrees Farhenheit), and 17 grams moisture per kilogram dry aid (75 grains moisture per pound of dry air) in determining compliance with the NO_x emission limit.

The proposed standards would be referenced to standard atmospheric conditions of 101.3 kilopascals (29.92 inches mercury), 29.4 degrees centigrade (85 degrees Fahrenheit), and 17 grams mositure per kilogram dry air (75 grains moisture per pound of dry air). Measured NO_x emission levels, therefore, would be adjusted to standard atmospheric conditions by use of ambient correction factors included in the standard. Manufacturers, owners, or operators may also elect to develop custom ambient condition correction factors, in terms of ambient temperature, and/or humidity, and/or ambient pressure. All correction factors would have to be substantiated with data and approved for use by EPA before they could be used for determining compliance with the proposed standards.

Emergency-standby IC engines and all one- and two-cylinder reciprocating gas engines would be exempt from the NO_x emission standard.

Summary of Environmental and Economic Impacts

The proposed standards would reduce uncontrolled NO_x emissions levels from stationary IC engines by about 40 percent. Based on industry growth projections, a reduction in national NO_x emissions of about 145,000 megagrams per year (160,000 tons per year) would be realized in the fifth year after the standards go into effect. Except for a few local areas (e.g., Los Angeles), there are currently no state standards liminting NO_x emissions from IC engines.

The proposed standards, however, would increase uncontrolled CO and HC emissions levels from stationary IC engines. Based on industry growth projections, an increase in national CO emissions of about 216,000 megagrams (238,000 tons) annually would be realized in the fifth year after the standards go into effect. Similarly, an increase in national total HC emissions of about 4600 megagrams (5000 tons) annually would be realized in the fifth year after the standards go into effect.

The large increase in CO emissions is due primarily to carbureted or naturally aspirated gas engines. These engines operate closer to stoichiometric conditions under which a small change in the air-to-fuel ratio results in a large increase in CO emissions.

Though total national CO emissions would increase significantly, ambient air CO concentrations in the immediate vicinity of these carbureted or naturally aspirated gas engines would not be adversely affected. As a result of the proposed standards of performance, the CO emissions from a naturally aspirated engine would increase about 160 percent. NO_x emissions from the same engine, however, would decrease concurrently about 40 percent.

Thus, there exists a trade-off between NO_x emissions reduction and CO emissions increase, particularly for carbureted or naturally aspirated gas engines. It should be noted though that CO emissions are considered to be a local problem since CO readily reacts to form CO_2. Additionally, most naturally aspirated gas engines are operated in remote locations where CO is not a problem. NO_x emissions, however, are linked to the formation of photochemical oxidants and are subject to long range transport. Also, NO_x emission control techniques are essentially design modifications, not add-on equipment. therefore, NO_x emissions reductions are much harder to achieve than CO or HC emissions reductions which may be achieved more easily from other sources.

One alternative is to propose a CO emissions limit based on the use of oxidizing catalysts. These catalysts can provide CO and HC emissions reductions on the order of 90 percent. Initial capital costs are high, however, averaging about $7500 for a typical 1000 horsepower naturally aspirated gas engine, or about 15 percent of the purchase price of this engine. EPA feels these costs for control of CO emissions are unreasonable.

The trade-off between NO_x and CO emissions appears reasonable. However, EPA invites comments from state and local air pollution control agencies, environmental groups, the industry, and other interested individuals concerning all aspects of the attractiveness of these standards which reduce NO_x emissions at the expense of CO emissions.

Industry has requested a waiver from the national mobile source standards for diesel engines used in light duty vehicles. Based on their tests, industry believes that the application of NO_x control techniques to these mobile diesel engines causes increased particulate (smoke) emissions. The plumes from most well maintained large-bore stationary IC engines, however, are virtually invisible when the engine is operating at steady state. Though excessive retard will cause diesel and dual fuel units to emit smoke, the NO_x control results used in the development of this standard were only considered if the plume did not exceed ten percent visibility. Therefore, EPA feels the NO_x control techniques used to meet the proposed standards for large stationary IC engines will not cause excessive visible and/or particulate emissions. However, EPA invites comments on the aspects of the proposed standards which reduce NO_x emissions at the expense of visible and/or particulate emissions.

There would be essentially no adverse water pollution, solid waste, or noise impact resulting from the proposed standards.

The energy impact of the proposed standards would be small. Turbocharged gas IC engine fuel consumption would be increased about two percent. Dual-fuel IC engine fuel consumption would be increased about three percent. Diesel IC engine fuel consumption would be increased about seven percent. Naturally aspirated gas IC engine fuel consumption would be increased by about eight percent. The fifth year energy impact of the proposed standards would be equivalent to an increase in fuel oil consumption of about 1.5 million barrels of oil per year (4,300 barrels of oil per day). This represents an increase of only 0.03 percent of the oil projected to be imported in the United States five years after the standards go into effect. In addition, these estimates are based on "worse-case" assumptions which yield the greatest energy impacts, and actual impacts are expected to be lower.

The economic impacts of the proposed standards are considered reasonable. The proposed standards would increase IC engine manufacturers' total capital investment requirements for developmental testing of engine models by about $5 million. These expenditures would be made over a two year period. Analysis of financial reports and other public financial information indicates that the manufacturers' overhead budgets are sufficient to support these requirements without adverse impact on their financial positions. The proposed standards would not give rise to a significant sales advantage for one or two manufacturers over competing manufacturers. The maximum intra-industry sales losses, based on "worst-case" assumptions, would be about six percent.

The proposed standards would increase the total annualized costs to users of a large stationary IC engines of all fuel types by about two to seven percent. The capital cost or purchase price of a large stationary IC engine would increase by about two percent.

The proposed standards would increase the total annualized costs for all engine users by about $32 million in the fifth year after standards go into effect. The total capital investment requirements for all users would equal about 9.6 million on a cumulative basis over the first five years the standards are in effect.

These impacts would result in price increases for the end products or services provided by the industrial and commercial users of large stationary IC engines. The electric utility industry would pass on a price increase after five years of 0.02 percent. After five years, delivered natural gas prices would increase 0.04 percent. Even after a full phase-in period of 30 years, during which new controlled engines would replace all existing uncontrolled engines, the electric utility industry would pass on a price increase of only 0.1 percent. Delivered natural gas prices would increase only 0.3 percent.

Rationale—Selection of Source for Control

Stationary IC engines are sources of NO_x, hydrocarbons (HC), particulates, sulfur dioxide (SO_x), and carbon monoxide (CO) emissions. NO_x emissions from IC engines, however, are of more concern than emissions of these other pollutants for two reasons. First, compared to total U.S. emissions for each pollutant, NO_x is the primary pollutant emitted by stationary engines. Second, EPA has assigned a high priority to development of standards of performance limiting NO_x emissions. A study by Argonne National Laboratory, "Priorities and Procedures for Development of Standards of Performance for New Stationary Sources of Atmospheric Emissions" (EPA-450/3-76-020), concluded that national NO_x emissions from stationary sources would increase by more than 40 percent between 1975 and 1990 in the absence of additional emission controls. Applying best technology to all sources would reduce this increase but would not prevent it from occurring. This unavoidable increase in NO_x emissions is attributable largely to the fact that current NO_x emission control techniques are based on combustion redesign. In addition, few NO_x emission control techniques can achieve large (i.e., in the range of 90 percent) reductions in NO_x emissions. Consequently, EPA has assigned a high priority to the development of standards of performance for major NO_x emission sources wherever significant reductions in NO_x can be achieved. Studies have shown that IC engines are significant contributors to total U.S. NO_x emissions from stationary sources. Internal combustion engines account for 16.4 percent of all stationary source NO_x emissions, exceeded only by utility and packaged boilers.

Studies have investigated the effect that standards of performance would have on nationwide emissions of particulates, NO_x, SO_x, HC, and CO from stationary sources. The "Priority List for New Source Performance Standards under the Clean Air Act Amendments of 1977," which was proposed in the August 31, 1978, Federal Register, ranked sources according to the impact, in tons per year, that standards promulgated in 1980 would have on emissions in 1990. This ranking placed spark ignition IC engines second and compression ignition IC engines third on a list of 32 stationary NO_x emission sources. Consequently, stationary IC engines have been selected for development of standards of performance.

Selection of Pollutants

Nitrogen oxides, hydrocarbons, and carbon monoxide.—Stationary IC engines emit the following pollutants: NO_x, CO, HC, particulates, and SO_x. The primary pollutant emitted by stationary IC engines is NO_x, accounting for over six percent (or 16 percent of all stationary sources) of the total U.S. inventory of NO_x emissions.

Stationary IC engines also emit substantial quantities of CO and HC. Numerous small (1–100 hp) spark ignition engines, which are similar to automotive engines, account for about 20 percent of the uncontrolled HC emissions and about 80 percent of the uncontrolled CO emissions. The large annual production of these small spark ignition engines (approximately 12.7 million), however, makes enforcement of a new source performance standard for this group difficult.

Large-bore engines, which account for three-quarters of NO_x emissions from stationary IC engines, contribute relatively small amounts to nationwide HC and CO emissions, especially if one considers that 80 percent of the HC emissions from large-bore IC engines are methane. An additional factor in considering CO and HC control is that inherent engine characteristics result in a trade-off between NO_x control and control of CO and HC.

As mentioned before, in some cases, particularly naturally aspirated gas engines, the application of NO_x emission control techniques could cause increases in CO and HC emissions. This increase in CO and HC emissions is strictly a function of the engine operating position relative to stoichiometric conditions, not the NO_x control technique. These engines operate closer to stoichiometric conditions under which a small change in the air-to-fuel ratio results in a large increase in CO emissions. Any increase in CO and HC emissions, however, represents an increase in unburned fuel and hence a loss in efficiency. Since IC engines manufacturers compete with one another on the basis of engine operating costs, which is primarily a function of engine operating efficiency, the marketplace will effectively ensure that CO and HC emissions are as low as possible following application of NO_x control techniques.

Though total national CO emissions would increase significantly, ambient air CO concentrations in the immediate vicinity of these carbureted or naturally aspirated gas engines would not be adversely affected. As a result of the proposed standards of performance, the CO emissions from a natually aspirated engine would increase about 160 percent. NO_x emissions from the same engine, however, would decrease concurrently about 40 percent.

Thus, there exists a trade-off between NO_x emissions reduction and CO emissions increase, particularly for carbureted or naturally aspirated gas engines. It should be noted though that CO emissions are considered to be a local problem as CO readily reacts to form CO_2. Additionally, most naturally aspirated gas engines are operated in remote locations where CO is not a problem. NO_x emissions, however, are linked to the formation of photochemical oxidants and are subject to long range transport. NO_x emissions reductions are also much harder to achieve than CO or HC emissions reductions which may be achieved more easily from other sources.

In addition, promulgation of CO standard of performance could, in effect, preclude significant NO_x control. NO_x emissions are primarily a function of combustion flame temperature. Decreasing the air-to-fuel ratio of a gas engine lowers the flame temperature and consequently reduces NO_x formation. As will be discussed later, this technique is the most effective means of reducing NO_x emissions from gas engines. CO emissions, however, are primarily a function of oxygen availability. Decreasing the air-to-fuel ratio reduces oxygen availability and consquently increases CO emissions. Hence naturally aspirated gas engines show a pronounced rise in CO emissions as the air-to-fuel mixture becomes richer (i.e., decreasing air-to-fuel ratio). Thus, placing a limit on CO emissions from internal combustion engines could effectively limit the decrease in the air-to-fuel ratio which would be applied to reduce NO_x emissions from naturally aspirated gas engines and, consequently, could limit the amount of NO_x emissions reduction achievable.

One alternative is to propose a CO emissions limit based on the use of oxidizing catalysts. These catalysts can provide CO and HC emissions reductions on the order of 90 percent. Initial capital costs are high, however, averaging about $7500 for a typical 1000 horsepower naturally aspirated gas engine, or about 15 percent of the purchase price of this engine. EPA feels these costs for control of CO emissions are unreasonable.

The trade-off between NO_x and CO emissions appears reasonable, and consequently, only NO_x emissions from large stationary IC engines were selected for control by standards of performance.

EPA, however, invites comments from state and local air pollution control agencies, environmental groups, the industry, and interested individuals concerning all aspects of the attractiveness of these standards which reduce NO_x emissions at the expense of CO emissions.

Particulate.—Virtually no data are available on particulate emission rates from stationary IC engines. It is believed, however, that particulate emissions from stationary IC engines are very low because the plumes from most of these engines are not visible. Therefore, neither particulate emissions nor visible emissions (plume opacity) were selected for control by standards of performance.

Sulfur oxides.—Sulfur oxides (SO_x) emissions from an IC engine depend on the sulfur content of the fuel and the fuel consumption of the engine. Scrubbing of IC engine exhausts to control SO_x emissions does not appear to be reasonable from an economic viewpoint. Therefore, the only viable means of controlling SO_x emissions would be combustion of low sulfur fuels. IC engines, however, currently burn low-sulfur fuels and will likely continue to do so because of the lower operating and maintenance costs associated with combustion of these fuels. Therefore, SO_x emissions were not selected for control by standards of performance.

Selection of Affected Facilities

A relatively small number of large-bore IC engines account for over 75 percent of all NO_x emissions from stationary engines. The remaining smaller bore IC engines, which make up the majority of all engine sales, are, from a NO_x emission standpoint, a considerably less significant segment of the industry. These engines have different emission characteristics due to their size, design, and operating parameters. The NO_x reduction technology developed for use on the large-bore IC engines may not be directly applicable to these smaller engines. Therefore, at this time, only large-bore engines have been selected for control by standards of performance.

Diesel engines.—The primary high usage (large emissions impact) domestic application of large-bore diesel engines during the past five years has been for oil and gas exploration and production. The market for prime (continuous) electric generation and other industrial applications all but disappeared after the 1973 oil embargo, but was quickly replaced by sales of standby electric units for building services, utilities, and nuclear power stations. The rapid growth in the oil and gas production market occurred because diesel units are being used on oil drilling rigs of various sizes. Sales of engines to export applications have also grown steadily since 1972, and are now a major segment of the entire sales market.

Medium-bore as well as large-bore engines are sold for oil and gas exploration, standby service, and other industrial applications. Applying standards of performance to medium-bore engines serving the same applications as large-bore designs would increase the number of affected facilities from about 200 to about 2,000 units per year (based on 1976 sales information) but consequently further reduce national NO_x emissions. Medium-bore sales accounted for significant NO_x emissions in 1976 (approximately 12,500 megagrams). It is estimated that approximately 25 percent, or about 500 of these units in high usage applications, accounted for most of the medium/bore NO_x emissions, since most of the remainder of these units were sold as standby generator sets. Though the potential achievable NO_x reduction is significant, this alternative causes the standard to apply to lower power engine models with fewer numbers of cylinders competing with other unregulated engines in different stationary markets. Additionally, considering this large number, and the remoteness and mobility of petroleum applications, this alternative would create serious enforcement difficulties. Consequently, a definition is required that distinguishes large-bore engines competing with medium-bore high power engines used for baseload electrical generation from large-bore engines competing solely with other large-bore engines.

One approach would be to define diesel engines covered by standards of performance as those exceeding 560 cubic inch displacement per cylinder (ie., CID/cyl). IC engines below this size are generally used for different applications than those above it. Considering the sizes and displacements offered by each diesel manufacturer and the applications served by diesel engines, this definition was selected as a reasonable approach for separating large-bore engines that compete with medium-bore engines from large-bore engines that compete solely with each other.

Dual-fuel engines.—The concept of dual-fuel operation was developed to take advantage of both compression ignition performance and inexpensive natural gas. These engines have been used almost exclusively for prime electric power generation. Shortages of natural gas and the 1973 oil embargo have combined to significantly reduce the sales of these engines in recent years. The few large-bore units that were sold (11 in 1976) were all greater than 350 CID/cyl.

Although a greater-than-350-CID/cyl limit would subject nearly all new dual-fuel sources to standards of performance, the criterion chosen to define affected diesel engines (i.e., greater than 560 CID/cyl) has also been selected for dual-fuel engines. The primary reason is that supplies of natural gas are likely to become even more scarce; thus dual-fuel engines will likely operate as diesel engines.

Gas engines.—The primary application of large-bore gas engines during the past five years has been for oil and gas production. The primary uses are to power gas compressors for recovery, gathering, and distribution. About 75 to 80 percent of all gas engine horsepower sold during the past five years was used for these applications. During this time, sales to pipeline transmission applications declined. Pipeline applications combined with standby power, electric generation, and other services (industrial and sewage pumping) accounted for the remaining 20 to 25 percent of horsepower sales. The growth of oil and gas production applications during this period corresponds to the increasing efforts to find new, or to recover marginal, gas reserves and distribute them to the existing pipeline transmission network.

It is estimated that the 400,000 horsepower of large-bore gas engine capacity sold for oil and gas production applications in 1976 emitted 35,000 megagrams of NO_x emissions, or nearly three times more NO_x than was emitted by the 200,000 horsepower of large-bore diesel engine capacity sold for the same application in that year. Thus, large-bore gas engines are primary contributors of NO_x emissions from new stationary IC engines, and standards of performance should be directed particularly at these sources.

If affected engines were defined as those greater than 350 CID/cyl, then all competing manufacturers of large-bore gas engines except one would be affected by the proposed standards of performance. This one manufacturer produces primarily medium-bore engines. Therefore, a 350 CID/cyl limit would give this one manufacturer an unfair competitive advantage over other large-bore engine manufacturers. Consequently, this definition should be lowered, or another definition adopted, to include the manufacturer in question. Either of the following two definitions would subject this manufacturer's gas engine to standards of performance:

- Greater than 240 CID/cyl
- Greater than 350 CID/cyl or greater than or equal to 8-cylinder and greater than 240 CID/cyl

Both measures would essentially include only this manufacturer's gas engines which compete with other manufacturer's large-bore gas engines. The second definition has a slight advantage over the first since it includes only gas engines produced by all manufacturers that have competitor counterparts of about the same power. Therefore, this second definition of affected gas engines was selected.

Rotary engines.—Rotary or wankel type engines have only recently been introduced as power sources in package stationary applications. These internal combustion engines convert energy in the fuel directly to rotary motion rather than through reciprocating pistons and a crankshaft. These engines consist of a triangular rotor rotating eccentrically inside an epitrochoidal housing.

Until recently the largest rotary engine in production was 90 cubic inches per rotor. Now, however, one manufacturer is producing a rotary engine with a displacement of 2,500 cubic inches per rotor. This engine is being offered as a one rotor model rated at 550 horsepower and a two rotor unit rated at 1,100 horsepower.

The displacement of the rotary engine is defined as the volume contained in the chamber, bordered by one flank of the rotor and the housing, at the instant the inlet port closes. These engines are presently sold as naturally aspirated gaseous fueled units primarily for fuel gathering compressors and power generation on offshore platforms.

NO_x emissions from these large rotary engines are similar to NO_x emissions from naturally aspirated four stroke, gaseous fuel reciprocating engines. Further sales of these engines are estimated to be 50,000 horsepower per year over the next five years. Since these large rotary engines contribute to NO_x emissions, standards of performance for new stationary IC engines should include these sources.

Due to design differences, rotary engines develop more power per cubic inch displacement than reciprocating engines. If the lower cutoff limit for affected rotary engines were 350 CID/rotor—in an attempt to equate displacement per cylinder and also use the same limit as for gaseous fueled engines—then rotary engines of approximately 100 horsepower would be regulated by standards of performance. Thus rotary engine manufacturers would be at a competitive disadvantage with unregulated reciprocating engine manufacturers in this power range. To ensure that the standards of performance do not alter the competitive position of the two types of engines, the lower size limit for affected rotary engines should correspond to an engine whose power output is the same as the smallest affected reciprocating unit.

Based on this criterion of equivalent horsepower, it is estimated that rotary engines greater than 1,500 CID/rotor would compete with reciprocating engines greater than 350 CID/cyc. Therefore, a greater than 1,500 CID/rotor definition of affected rotary engines is selected to subject these engines to standards of performance. The definition applies to rotary engines of all fuel types.

Exemptions.—One and two cylinder reciprocating engines could be covered by the above definitions. These engines, however, account for less than 10 percent of all engine horsepower and therefore are less significant NO_x emitters. Additionally, the engines operate at a small fraction of their power output and probably have lower NO_x emissions than the larger, high rated engines. Therefore, all one and two cylinder reciprocating engines were exempted from standards of performance.

Emergency standby engines also require special consideration. These engines operate less than 200 hours per year under all but very unusual circumstances. Consequently, they add relatively little to regional or national total NO_x emissions. The largest category of emergency standby units is for nuclear power plants, where these engines provide power for the pumps used for cooling the reactors. These engines must attain a set speed in ten seconds and must assume full rated load in 30 seconds. In some cases, application of the demonstrated NO_x control technique limits the responsiveness of these engines in emergency situations. Therefore, all emergency standby engines are exempted from standards of performance.

Selection of Best System of Emission Reduction

Four emission control techniques, or combinations of these techniques, have been identified as demonstrated NO_x emission reduction systems for stationary large-bore IC engines. These techniques are: (1) Retarded ignition or fuel injection, (2) air-to-fuel ratio changes, (3) manifold air cooling, and (4) derating power output (at constant speed). In general, all four techniques are applied by changing an engine operating adjustment.

Fuel injection retard is the most effective NO_x control technique for diesel engines. Similarly, air-to-fuel ratio change is the most effective NO_x control technique for gas engines. Both retard and air-to-fuel ratio changes are effective in reducing NO_x emissions from dual-fuel engines.

Other NO_x emission control techniques exist but are not considered feasible alternatives. Of these other techniques, catalytic reduction of NO_x emissions through the use of systems similar to automobile catalyst systems is probably the first to come to mind. Most large stationary IC engines operate at air-to-fuel ratios that are typically much greater than stoichiometric, and consequently the engine exhaust is characterized by high oxygen (O_2) concentrations. Existing automobile catalytic converters, however, operate near stoichiometric conditions (i.e., low exhaust O_2 concentrations). These automobile catalysts are not effective in reducing NO_x in the presence of high O_2 concentrations.

Consequently, entirely different catalyst systems would be needed to reduce NO_x emissions from large stationary IC engines. Although such catalyst systems are currently under development and have been demonstrated for one very narrow application (i.e., fuel-rich naturally aspirated gas engines), they have not been demonstrated for the broad range of IC engines manufactured, such as turbocharged engines, fuel-lean gas engines, or diesel engines. For these engines the reduction of NO_x by ammonia injection over a precious metal (e.g., platinum) catalyst appears promising with NO_x reductions of approximately 90 percent having been reported; however, the cost of such a system is high.

For a typical 1000 horsepower engine approximately two cubic feet of honeycomb catalyst (platinum based) would be required to ensure proper operation of the system. The cost of the catalyst was estimated at $1,500/cubic foot (in 1973). Assuming that the engine costs $150/hp and that the cost of the catalyst accounts for about one-half the cost of the whole system (container, substrate, and catalyst), the capital investment for this control system represents approximately four percent of the engine purchase price.

The amount of ammonia required for an ammonia/catalyst NO_x reduction system will depend on the NO_x emission rate (g/hp-hr). Based on uncontrolled NO_x emission rates of 9 to 22 g/hp-hr, and the cost of $150/ton for the ammonia, the cost impact of injecting ammonia is approximately 5 to 15 percent of the total annual operating costs ($/hp-hr) for natural gas engines. When this operating cost is combined with the capital cost of the catalytic system discussed above, the total cost increase is about 25 percent. Therefore, in continuous service applications this system is expensive compared to control techniques such as retard or air-to-fuel changes.

It is also important to note that the consumption of ammonia can be expressed as a quantity of fuel since natural gas is generally used to produce ammonia. Assuming a conservative NO_x emission rate of 20 g/hp-hr, and engine heat rate of 7500 Btu/hp-hr, a heating value of 21,800 Btu/lb for natural gas, and a requirement for approximately 900 lbs of gas per ton of ammonia produced,* then the ammonia necessary for the catalytic reduction has the same effect on the supply of natural gas as a two percent increase in fuel consumption. Additional fuel is required to operate the plant which produces the ammonia.

Catalytic reduction, therefore, is currently not a demonstrated NO_x emission control technique which could be used by all IC engines. Consequently, although catalytic reduction of NO_x emissions could be used in a few isolated cases to comply with standards of performance, it could not be used as the basis for developing standards of performance which are applicable to all IC engines.

The data and information presented in the Standards Support and Environmental Impact Statement clearly indicate that the four demonstrated control techniques mentioned above will reduce NO_x emissions from IC engines. Due to inherent differences in the uncontrolled emission characteristics of various engines, it is difficult to draw conclusions from this data and information concerning the ability of these emission control techniques to reduce NO_x emissions from all IC engines to a specific level. In general, engines with high uncontrolled NO_x emissions levels have relatively high controlled NO_x emissions levels and engines with low uncontrolled NO_x emissions levels have relatively low contolled NO_x emissions levels. To eliminate these inherent differences in NO_x emission characteristics among various engines, the data were analyzed in terms of the degree of reduction in NO_x emissions as a function of the degree of application of each emission control technique.

Ignition retard in excess of eight degrees in diesel engines frequently leads to unacceptably high exhaust temperatures, resulting in exhaust value and/or turbocharger turbine damage. Similarly, changes in the air-to-fuel ratio in excess of five percent in gas engines frequently lead to excessive misfiring or detonation which could lead to a serious explosion in the exhaust manifold. Eight degrees of ignition retard in diesel engines and five percent change in air-to-fuel ratios in gas engines yield about a 40 percent reduction in NO_x emissions. Consequently, in light of these limitations to the application of these emission control techniques, it is apparent that a 40 percent reduction in NO_x emissions is the most stringent regulatory option which could be selected as the basis for standards of performance. An alternative of 20 percent NO_x emission reduction was also considered a viable regulatory option which could serve as the basis for standards of performance.

Environmental impacts.—Standards of performance based on alternative I (20 percent reduction) would reduce national NO_x emissions by 72,500 megagrams annually in the fifth year after the standards went into effect. In contrast, standards of performance based on alternative II (40 percent reduction) would reduce national NO_x emissions by about 145,000 megagrams annually in the fifth year after the standards went into effect. Thus, standards of performance based on alternative II would have a much greater impact on national NO_x emissions than standards based on alternative I.

Standards of performance based on either alternative would, with the exception of naturally aspirated gas engines, result in a small increase in carbon monoxide (CO) and hydrocarbon emissions (HC) from most engines. A typical diesel engine with a sales-weighted average uncontrolled CO emission level of approximately 2.9 g/hp-hr would experience an increase in CO emissions of about 0.75 g/hp-hr to comply with standards of performance based on alternative I, and an increase of about 1.5 g/hp-hr to comply with standards of performance based on alternative II. Total hydrocarbon emissions would increase a sales-weighted average uncontrolled emission level of 0.3 g/hp-hr by about 0.06 g/hp-hr to comply with standards based on alternative I, and would increase by about 0.1 g/hp-hr to comply with standards of performance based on alternative II.

Similarly, a typical dual-fuel engine with a sales-weighted average uncontrolled CO emission level of approximately 2.7 g/hp-hr would experience an increase in CO emissions of about 1.2. g/hp-hr and about 2.7 g/hp-hr to comply with standards of performance based on alternatives I and II, respectively. Total HC emissions, however, would increase by about 0.3 g/hp-hr from a sales-weighted average uncontrolled level of approximately 2.8 g/hp-hr to comply with standards of performance based on alternative I. To comply with standards of performance based on alternative II total hydrocarbon emissions would decrease by 0.6 g/hp-hr.

A typical turbocharged or blower scavenged gas engine with a sales-weighted average uncontolled CO emission level of approximately 7.7 g/hp-hr would experience an increase in CO emissions of about 1.9 g/hp-hr to comply with standards of performance based on alternative I and about 3.8 g/hp-hr to comply with standards of performance based on alternative II. Total hydrocarbon emissions would increase a sales-weighted average uncontrolled level of approximately 1.9 g/hp-hr by about 0.2 g/hp-hr to comply with standards of performance based on alternative I. To comply with standards of performance based on alternative II total hydrocarbon emissions would increase by about 0.4 g/hp-hr.

A typical naturally aspirated gas engine with a sales-weighted average uncontrolled CO emission level of approximately 7.7 g/hp-hr would experience an increase in CO emissions of about 3.9 g/hp-hr to comply with standards of performance based on alternative I and about 17 g/hp-hr to comply with standards of perfomance based on alternative II. Total hydrocarbon emissions would increase a sales-weighted average uncontrolled level of approximately 1.8 g/hp-hr by about 0.04 g/hp-hr to comply with standards of performance based on alternative I. To comply with standards of performance based on alternative II total hydrocarbon emissions would increase by about 0.08 g/hp-hr.

As noted earlier, the increase in ambient air CO levels resulting from compliance with NO_x standards of performance based on either alternative would be insignificant compared to the NAAQS of 10 mg/m^3 for CO. Additionally, CO emissions are a local problem as CO readily reacts to form CO_2. Additionally, most naturally aspirated engines are operated in remote or sparcely populated areas, CO emissions will not present a problem.

Currently, national stationary CO emissions are approximately 33 million megagrams per year. Standards of performance based on alternative I would increase these emissions by approximately 63,000 megagrams annually in the fifth year after the standards went into effect. In contrast, standards of performance based on alternative II would increase national CO emissions by about 216,000 megagrams annually in the fifth year after the standards went into effect.

Standards of performance based on alternative I would increase national total HC emissions by about 2,300 megagrams annually in the fifth year after the standards went into effect compared to an increase of about 4,600 megagrams annually associated with alternative II. It is estimated that more than 90 percent of total HC emissions from large-bore gas-fuel engines and 75 percent of total HC emissions from large-bore dual-fuel engines are methane, which is nonreactive and does not lead to oxidant formation. Standards of performance based on alternative I would increase national reactive HC emissions by approximately 108 megagrams annually in the fifth year after the standards went into effect, compared to an increase of approximately 216 megagrams annually associated with alternative II.

Stationary IC engines are sources of NO_x, HC, and CO emissions, with both NO_x and HC contributing to oxidant formation. With regard to regulation of emissions from IC engines, NO_x emissions are of more concern than emissions of HC for two reasons. First, NO_x is emitted in greater quantities from stationary IC engines than HC. Second, as mentioned earlier, a high priority has been assigned to development of standards of perfomance limiting NO_x emissions. A study by Argonne National Laboratory, "Priorities and Procedures for development of Standards of Perfomance for New Stationary Sources of Atmospheric Emissions," concluded that national NO_x emissions from stationary sources would increase by more than 40 percent between 1975 and 1990 in the absence of additional emission controls. The slight increase in HC emissions from IC engines associated with control of NO_x can be offset in most cases from other sources more easily than NO_x emissions can be reduced from other sources. Therefore, the adverse enviromental impact of increased HC emissions because of the reduction in NO_x emissions is considered small.

There would be essentially no water pollution, solid waste, or noise impact of standards of performance based on either alternative I or alternative II.

Thus, as reflected in Table I, the environmental impacts of standards of performance based on either alternative are small and reasonable.

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TABLE I

ENVIRONMENTAL IMPACTS OF ALTERNATIVES

Pollutant	Base Level[a]	Alternative I	Alternative II
National NO_x Emissions	14.6×10^6 megagrams	Reduced by 72,500 megagrams annually in the fifth year after standard goes into effect	Reduced by 145,000 megagrams annually in the fifth year after standard goes into effect
National CO Emissions	33.0×10^6 megagrams	Increased by 63,000 megagrams annually in the fifth after standard goes into effect	Increased by 216,000 megagrams annually in the fifth after standard goes into effect
National Total HC Emissions	10.2×10^6 megagrams	Total Hydrocarbons Increased by 2,300 megagrams annually in the fifth year after standard goes into effect Reactive Hydrocarbons Increased by 108 megagrams annually in the fifth year after standard goes into effect	Total Hydrocarbons Increased by 4,600 megagrams annually in the fifth year after standard goes into effect Reactive Hydrocarbons Increased by 216 megagrams annually in the fifth year after standard goes into effect
Water Pollution	--	No increase	No increase
Solid Waste	--	No increase	No increase
Noise	--	No adverse impact	No adverse impact

aTotal U.S. emission from stationary sources as per EPA Nationwide Air Pollutant Inventory for 1975

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Energy impacts. The potential energy impact of standards of performance based on either alternative is small. Standards of performance based on alternative I would increase the fuel consumption of a typical blower-scavenged or turbocharged gas engine by approximately one percent, whereas standards of performance based on alternative II would increase the fuel consumption by approximately two percent.

Standards of performance based on alternative I would increase the fuel consumption of a typical dual-fuel engine by about one percent. Standards of performance based on alternative II, however, would increase the fuel consumption by three percent. Standards of performance based on alternative I would increase the fuel consumption of a typical naturally aspirated gas engine by approximately six percent. Standards of performance based on alternative II, however, would increase the fuel consumption by approximately eight percent.

Standards of performance based on alternative I would increase the fuel consumption of a typical diesel engine by approximately three percent. Standards of performance based on alternative II, however, would increase the fuel consumption by approximately seven percent.

The potential energy impact in the fifth year after the standards go into effect, based on alternative I, would be equivalent to an increase in fuel consumption of approximately 1.03 million barrels of oil per year compared to the uncontrolled fuel consumption of IC engines affected by the standards of 31 million barrels per year. The potential energy impact in the fifth year after the standard goes into effect, based on alternative II, would be equivalent to approximately 1.5 million barrels of oil per year.

It should be noted that the largest increase represents only 0.02 percent of the 1977 domestic consumption of crude oil and natural gas. The largest increase also represents only 0.03 percent of the projected total oil imported to the U.S. five years after the standards go into effect.

Thus, the energy impacts of standard of performance based on either alternative are small and reasonable.

Economic impact of alternatives. Manufacturers of stationary IC engines would incur additional costs due to standards of performance. These costs, however, would be small. It is estimated that the total cost to the manufacturers for each engine model family, including development, durability tests, and retooling, would be approximately: (1) $125,000 for retard and air-to-fuel change; (2) $150,000 for manifold air temperature reduction; and (3) $25,000 for derate. For each manufacturer therefor, total costs would vary depending on (1) the number of engine model families produced; (2) their degree of advancement in emission testing; (3) the uncontrolled emission levels of their engines; (4) the development and durability testing required to produce engines that can meet proposed standards of performance; and (5) the emission control technique selected for NO_x emission reduction.

The manufacturer's total capital investment requirements for developmental testing of engine models is estimated to be about $4.5 million to comply with standards of performance based on alternative I and about $5 million to comply with standards of performance based on alternative II. These expenditures would be made over a two year period. Analyses of the financial statements and other public financial information of engine manufacturers or their parent companies indicate that the manufacturer's overhead budgets are sufficient to support the development of these controls without adverse impact on their financial position.

Manufacturers would not experience significant differential cost impacts among competing engine model families. Consequently, no significant sales advantages or disadvantages would develop among competing manufacturers as a result of standards of performance based on either alternative. Based on "worst-case" assumptions, the maximum intra-industry sales losses would be about six percent as a result of standards of performance based on either alternative. Thus, the intra-industry impacts would be moderate and not cause any major dislocations within the industry.

The total annualized cost penalities imposed on IC engines by standards of performace would also have very little impact with regard to increasing sales of gas turbines. Standards of performance based on alternative I would result in no loss of sales to gas turbines whereas standards of performance based on alternative II could result in the possible loss of sales for one diesel manufacturer.

It should be noted that this conslusion is based on limited data. It is quite likely, however, that this manufacturer's line of diesel engines, through minor combustion modifications, could reduce its NO_x emissions as discussed in the SSEIS to levels comparable to those of other manufacturers. Further, due to technical limitations, economic considerations, and customer preference, it is unlikely that IC engine users would switch to gas turbines. Thus, the impact on sales would be minimal.

Therefore, the economic impacts on the manufacturers of standards of performance based on either alternative are considered small and reasonable.

The application of NO_x controls will also increase costs to the engine user. The magnitude of this increase will depend upon the amount and type of emission control applied. Fuel penalties are the major factor affecting this increase.

The following four end uses represent the major applications of diesel, dual-fuel, and natural gas engines: (1) Diesel engine, electrical generation; (2) dual-fuel engine, electrical generation; (3) gas engine, oil and gas transmission and (4) gas engine, oil and gas production.

The manufacturers' capital budget requirements to develop and test engine NO_x control techniques would be regarded as an added expense and most likely passed on to the engine users in the form of higher prices. Therefore, users of IC engines would have to expend additional capital to purchase more expensive engines. This capital cost penalty, however, is small. A two percent increase in engine price would be expected on the average as the result of standards of performance based on either alternative. Typical initial costs for uncontrolled diesel and dual-fuel, electrical generation engines, and natural gas oil and gas transmission engines are about $150/hp. Initial costs for gas, gas production engines are about $50/hp.

The total additional capital cost for all users would equal about $9.6 million on a cumulative basis over the first five years to comply with standards of performance based on either alternative.

As mentioned earlier, fuel penalties are the major factor affecting the total annualized cost of high usage engines. The total annualized cost of a typical uncontrolled diesel, electrical generation engine is about 2.5¢/hp-hr. As a result of standards of performance based on alternative I this total annualized cost would increase by about 0.04¢/hp-hr (1.5 percent). As a result of standards of performance based on alternative II this total annualized cost would increse by about 0.11¢/hp-hr (4.5 percent).

The total annualized cost of a typical uncontrolled dual-fuel electrical generation engine is about 2.8¢/hp-hr. As a result of standards of performance base on alternative II this total annualized cost would increase by about 0.07¢/hp-hr (2.5 percent). As a result of standards of performance based on alternative Ii this total annualized cost would increase by about 0.09¢/hp-hr (3.2 percent).

The total annualized cost of a typical uncontrolled gas, oil and gas transmission engine is about 2.2¢/hp-hr. As a result of standards of performance based on alternative I this total annualized cost would increase by about 0.02¢/hp-hr (1 percent). As a result of standards of performance based on alternative II this total annualized cost would increase by about 0.04¢/hp-hr (2 percent).

The total annualized cost of a typical uncontrolled gas, oil and gas production engine is about 2.2¢/hp-hr. As a result of standards of performance based on alternative I this total annualized cost would increase by about 0.14¢/hp-hr (6.5 percent). As a result of standards of performance based on alternative II this total annualized cost would increase by about 0.16¢/hp-hr (7.5 percent).

Thus, the total annualized cost penalties to the user associated with either alternative are small. Total uncontrolled annualized costs of about $580 million by all large stationary IC engine users would increase by about $25 million to comply with standards of performance based on alternative I and would increase by about $32 million to comply with standards of performance based on alternative II in the fifth year after the standards go into effect.

The economic impacts on users arising from the cost penalties outlined above would be small. In general, these impacts translate into price increases for the end products or services provided by the industrial and commercial users of large stationary IC engines. The electric utility industry would pass on a price increase after five years of 0.02 percent to comply with standards of performance based on either alternative. After five years, delivered natural gas prices would increase 0.02 percent if standards of performance based on alternative I were applied and 0.04 percent if standards of performance based on alternative II were applied.

Even after a full phase-in period of 30 years, during which new controlled engines would replace all existing uncontrolled engines, the electric utility industry would realize a price increase of only 0.1 percent to comply with standards of performance based on either alternative. Similarly, delivered natural gas prices would increase only 0.1 percent if standards of performance based on alternative I were applied and 0.3 percent if standards of performance based on alternative II were applied. Thus, as summarized in Table II, the economic impacts of standards of performance based on either alternative are considered small and reasonable.

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TABLE II

ECONOMIC IMPACTS OF ALTERNATIVES

Impact	Uncontrolled Level of Cost	Alternative I	Alternative II
Impact on Manufacturer			
Capital budget requirements	--	$4.5 million over two years; able to generate internally from profits.	$5 million over two years; able to generate internally from profits.
Intra-industry competition	--	Maximum sales loss unlikely to exceed 6% of internal combustion engine sales for any firm.	6% maximum loss for any firm
Competition from gas turbines	--	No losses.	Possible sales loss for one diesel manufacturer.
Impact on End-Use Applications			
Total annualized cost[a]			
Diesel fuel, electrical generation	2.5¢/hp-hr	Base increased by 0.04¢/hp-hr	Increased by 0.11¢/hp-hr
Dual-fuel, electrical generation	2.8¢/hp-hr	Increased by 0.07¢/hp-hr	Increased by 0.09¢/hp-hr
Natural gas fuel, oil and gas transmission	2.2¢/hp-hr	Increased by 0.02¢/hp-hr	Increased by 0.04¢/hp-hr
Natural gas fuel, oil and gas production	2.2¢/hp-hr	Increased by 0.14¢/hp-hr	Increased by 0.16¢/hp-hr
Totals of all new engines after 5 years	$580 million	Increased by $25 million	Increased by $32 million
Capital Cost Penalty[a]			
Diesel fuel, electrical generation or dual fuel, electrical generation or natural gas fuel, oil and gas transmission	$150/hp	Increased by $3.00/hp	Increased by $3.00/hp
Natural gas fuel, oil and gas production	$ 50/hp	Increased by $1.00/hp	Increased by $1.00/hp
Totals etc.	$450 million	$9.6 million on a cumulative basis over first 5 years after standards go into effect.	$9.6 million on a cumulative basis over first 5 years after standards go into effect.
Impact on Product Prices and Users			
Electricity prices	--	U.S. electric bill up 0.02% after 5 years. U.S. electric bill up 0.1% after full phase-in.	U.S. electric bill up 0.02% after 5 years. U.S. electric bill up 0.1% after full phase-in[b].
Gas prices	--	Delivered natural gas prices up 0.02% after 5 years. Delivered natural gas prices up 0.1% after full phasein.	Delivered natural gas prices up 0.04% after 5 years. Delivered natural gas prices up 0.3% full phasein.

[a] Assumed typical 2000 horsepower engine operating 8000 hours per year in all cases

[b] Full phase-in implies replacement of all existing engines

Based on the assessment of the impacts of each alternative, and since alternative II achieves a greater degree of NO_x reduction, it is selected as the best technological system of continuous emission reduction of NO_x from stationary large-bore IC engines, considering the cost of achieving such emission reduction, any nonair quality health and environmental impact, and energy requirements.

Selection of Format for the Proposed Standards

A number of different formats could be used to limit NO_x emissions from large stationary IC engines. Standards could be developed to limit emissions in terms of: (1) Percent reduction; (2) mass emissions per unit of energy (power) output; or (3) concentration of emissions in the exhaust gases discharged to the atmosphere.

Analysis of the effectiveness of the various NO_x emission control techniques clearly shows that the ability to achieve a percent reduction in NO_x emissions is what has been demonstrated. However, a percent reduction format is highly impractical for two reasons. First, a reference uncontrolled NO_x emission level would have to be established for each manufacture's engine, a difficult task since some manufacturers produce as many as 25 models which are sold with several ratings. Second, a reference uncontrolled NO_x emission level would have to be established for any new engines developed after promulgation of the standard. This would be quite simple for engines that employed NO_x control techniques such as ignition retard or air-to-fuel ratio change to comply with standards of performance. Emissions could be measured without the use of these techniques. For engines designed to comply with the standards through the use of combustion chamber modifications, however, this would not be possible. Thus, new engines would receive no credit for the NO_x emission reduction achieved by combustion chamber redesign and this would effectively preclude the use of this approach to comply with the standards.

A mass-per-unit-of-energy-output format, typically referred to as brake-specific emissions (g/hp-hr), relates the total mass of NO_x emissions to the engine's productivity. Although brake-specific mass standards (g/hp-hr) appear meaningful becasue they relate directly to the quantity of emissions discharged into the atmosphere, there are disadvantages in that enforcement of mass standards would be costly and complicated in practice. Exhaust flow and power output would have to be determined in addition to NO_x concentration. Power output can be determined from an engine dynamometer in the laboratory, but dynamometers cannot be used in the field. Power output could be determined by: (1) Inferring the power from engine operating parameters (fuel flow, rpm, manifold pressure, etc.); or (2) inferring engine power from the output of the generator or compressor attached to the engine. In practice, however, these approaches are time consuming and are less accurate than dynamometer measurements.

Another possible format would be to limit the concentration of NO_x emissions in the exhaust gases discharged to the atmosphere. Concentrations would be specified in terms of parts-per-million volume (ppm) of NO_x. The major advantage of this format is its simplicity of enforcement. As compared to the formats discussed previously, only a minimum of data and calculations are required, which decreases testing costs and minimizes errors in determining compliance with an emission standard since measurements are direct.

The primary disadvantages associated with concentration standards are: (1) A standard could be circumvented by dilution of exhaust gases discharged into the atmosphere, which lowers the concentration of pollutant emissions but does not reduce the total pollutant mass emitted; and (2) a concentration standard could penalize high efficiency engines. Both these problems, however, can be overcome through the use of appropriate "correction" factors.

Since the percent reduction format is impractical, and the problems associated with the enforcement of mass standards (mass-per-unit energy output) appear to outweigh the benefits, the concentration format was selected for standards of performance for large stationary IC engines.

As mentioned above, because a concentration standard can be circumvented by dilution of the exhaust gases, measured concentrations must be expressed relative to some fixed dilution level. For combustion processes, this can be accomplished by correcting measured concentrations to a reference concentration of O_2. The O_2 concentration in the exhaust gases is related to the excess (or dilution) air. Typical O_2 concentrations in large-bore IC engines can range from 8 to 16 percent but are normally about 15 percent. Thus, referencing the standard to a typical level of 15 percent O_2 would prevent circumvention by dilution.

As also mentioned above, selection of a concentration format could penalize high efficiency IC engines. These highly efficient engines generally operate at higher temperature and pressures and, as a result, discharge gases with higher NO_x concentrations than less efficient engines, although the brake-specific mass emissions from both engines could be the same. Thus, a concentration standard based on low efficiency engines could effectively require more stringent controls for high efficiency engines. Conversely, a concentration standard based on high efficiency engines could allow such high NO_x concentrations that less efficient engines would require no controls. Consequently, selecting a concentration format for standards of performance requires an efficiency adjustment factor to permit higher NO_x emissions from more efficient engines.

The incentive for manufacturers to increase engine efficiency is to lower engine fuel consumption. Therefore, the objective of an efficiency adjustment factor should be to give an emissions credit for the lower fuel consumption of more efficient IC engines. Since the fuel consumption of IC engines varies linearly with efficiency, a linear adjustment factor is selected to permit increased NO_x emissions from highly efficient IC engines.

The efficiency adjustment factor needs to be referenced to a baseline efficiency. Most large existing stationary IC engines fall in the range of 30 to 40 percent efficiency. Therefore, 35 percent is selected as the baseline efficiency.

The efficiency adjustment factor included in the proposed standards permits a linear increase in NO_x emissions for engine efficiencies above 35 percent. This adjustment would not be used to adjust the emission limit downward for IC engines with efficiencies of less than 35 percent. This efficiency adjustment factor also applies only to the IC engine itself and not the entire system of which the engine may be a part. Since Section 111 of the Clean Air Act requires the use of the best system of emission reduction in all cases, this precludes the application of the efficiency adjustment factor to an entire system. For example, IC engines with waste heat recovery may have a higher overall efficiency than the IC engine alone. Thus, the application of the efficiency adjustment factor to the entire system would permit greater NO_x emissions because of the system's higher overall efficiency, and would not necessarily require the use of the best demonstrated system emission reduction on the IC engine.

Selection of Numerical Emission Limits

Overall approach.—As mentioned earlier it is difficult to select a specific NO_x emission limit which all IC engines could meet primarily through the use of ignition retard or air-to-fuel ratio change. Because of inherent differences among various IC engines with regard to uncontrolled NO_x emission levels, there exists a rather large variation within the data and information included in the Standards Support and Environmental Impact Statement concerning controlled NO_x emission levels. Generally speaking, engines with relatively low uncontrolled NO_x emissions levels achieved low controlled NO_x emissions levels and engines with high uncontrolled NO_x emissions levels achieved relatively high controlled NO_x emissions levels. Consequently, the following alternatives were considered for selecting the numerical concentration emission limits based on a 40 percent reduction in NO_x emissions:

1. Apply the 40 percent reduction to the highest observed uncontrolled NO_x emission level.
2. Apply the 40 percent reduction to a sales-weighted average uncontrolled NO_x emission level.
3. Apply the 40 percent reduction to this sales-weighted average uncontrolled NO_x emission level plus one standard deviation.

The highest observed uncontrolled NO_x emission levels for gas, dual-fuel and diesel engines are as follows: (1) Gas, 29 g/hp-hr. (2) dual-fuel, 15 g/hp-hr, and (3) diesel. 19 g/hp-hr.

Sales-weighted uncontrolled NO_x emission levels were determined by applying a sales-weighting to each manufacturer's average uncontrolled NO_x emissions for engines of each fuel type. The sales-weighting, based on horsepower sold, gives more weight to those engine models which have the highest sales. The sales-weighted average uncontrolled NO_x emission level for each engine fuel type are as follow: (1) Gas. 15 g/hp-hr. (2) dual-fuel, 8 g/hp-hr. and (3) diesel, 11 g/hp-hr.

The third alternative incorporates a "margin for engine variability" by adding one standard deviation to the sales-weighted average uncontrolled NO_x emission level and then applying the 40 percent reduction. Standard deviations were calculated from the uncontrolled NO_x emission data included in the Standards Support and Environmental Impact Statement, assuming the data had normal distribution. A subsequent statistical evaluation of the data indicated that this assumption was valid. The standard deviations for each engine fuel type are as follows: (1) Gas. 4 g/hp-hr. (2) dual-fuel, 3.2 g/hp-hr. and (3) diesel, 3.7 g/hp-hr.

The standard deviation of the uncontrolled NO_x emission data base is relatively large compared to the sales-weighted average uncontrolled NO_x emission level for each engine type. This indicates that the distribution of uncontrolled NO_x emissions levels is quite broad. In addition, the standard deviation is of the same magnitude as the 40 percent reduction in NO_x emissions that can be achieved. Thus, regardless of which alternative approach is followed to select the numerical NO_x concentration emission limit, a significant portion of the IC engine population may have to achieve more or less than a 40 percent reduction in NO_x emissions to comply with the standards.

It is important to note that the 40 percent reduction in NO_x emissions is based on the application of a single control technique, such as ignition retard, or air-to-fuel ratio change. Other emission control techniques, however, such as manifold air cooling and engine derate, exist, although they are generally not as effective in reducing NO_x emissions. Since emission control techniques are additive to some extent, it is possible in a number of cases to reduce NO_x emissions by greater than 40 percent.

The following factors were examined for each engine type to choose the alternative for selecting the numerical NO_x concentration emission limit: (1) The percentage of engines that would have to reduce NO_x emissions by 40 percent or less to meet the standards; (2) the percentage of engines that would be required to do nothing to meet the standards; and (3) the percentage of engines that would be required to reduce NO_x emissions by more than 40 percent to meet the standards. The normal distribution curve presented in Figure I illustrates the trade-offs among the three alternatives for selecting the numerical NO_x concentration emission limit.

The first alternative is to apply the 40 percent reduction to the highest uncontrolled NO_x emission level within a fuel category. For example, 29 g/hp-hr is the highest uncontrolled NO_x emission level for gas engines. The application of a 40 percent reduction would lead to an emission level of about 17 g/hp-hr. As illustrated in Figure I, if this level were selected as a standard of performance, 99 percent of production gas engines could easily meet the emission limit by reducing emissions by 40 percent or less. However, 69 percent of production engines would not have to reduce NO_x emissions at all. Only one percent of production engines would have to reduce NO_x emissions by more than 40 percent.

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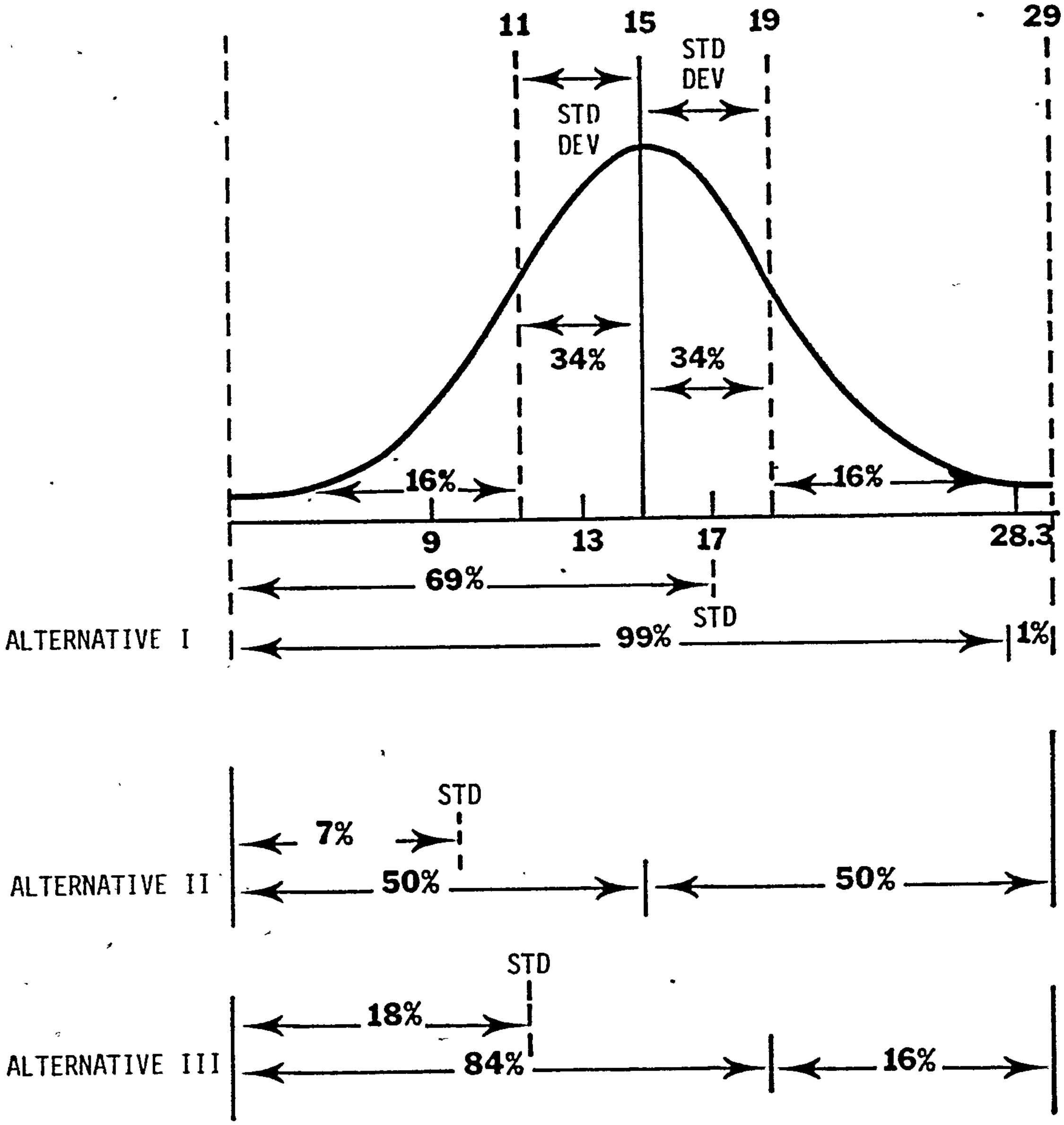

FIGURE 1. Statistical effects of alternative emission limits on gas engines.

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The second alternative is to apply 40 percent reduction to the sales-weighted average uncontrolled NO_x emission level. For example, the sales-weighted avergage uncontrolled NO_x level for gas engines is 15 g/hp-hr. The application of a 40 percent reduction would lead to a NO_x emission level of 9 g/hp-hr. As illustrated in Figure I, if this level were selected as a standard of performance, 50 percent of production gas engines could meet the standard with 40 percent or less reduction in NO_x emissions. However, 50 percent of production gas engines would be required to reduce NO_x emissions by greater than 40 percent. Only seven percent of production gas engines would not have to reduce NO_x emissions at all.

The third alternative is to base the standards on a 40 percent reduction in NO_x emissions from the sales-weighted average uncontrolled NO_x emission level plus one standard deviation. For example, the sales-weighted average uncontrolled NO_x emission level for gas production gas engines is 15 g/hp-hr and the standard deviation of the production gas engine data base is 4 g/hp-hr. Thus, the application of a 40 percent reduction to the sum of these two values would lead to an emission level of 11 g/hp-hr. As illustrated in Figure I, if this level were selected as a standard of performance, 84 percent of the production gas engines could easily meet the emission limit by reducing emissions by 40 percent or less. However, 18 percent of the production gas engines would not have to reduce NO_x emission at all. Only 16 percent of the production gas engines would have to reduce NO_x emissions by more than 40 percent.

This same analysis applied to dual-fuel and diesel engines leads to the results summarized in Table III. If standards of performance were based on Alternative I, essentially all engines could achieve the emission limit by reducing NO_x emissions 40 percent or less. A significant reduction in NO_x emissions would not be achieved, however, since 50 to 70 percent of the IC engines would not have to reduce NO_x emissions at all. If the standards of performance were based on Alternatve II, about 50 percent of the IC engines (in all categories) would have to reduce NO_x emissions by greater than 40 percent. Less than 10 percent would not have to reduce NO_x emissions at all. Thus this alternative would achieve a significant reduction in NO_x emissions from new sources. If standards of performance were based on Alternative III, the results would be similar to those achieved with Alternative I. About 85 percent of engines could easily meet the standards by reducing NO_x emissions by less than 40 percent. About 20 to 30 percent of IC engines would not have to reduce NO_x emissions at all, and about 15 percent of IC engines would have to reduce NO_x emissions by more than 40 percent.

In light of the high priority which has been given to standards directed toward reducing NO_x emissions and the significance of IC engines in terms of their contribution to NO_x emissions from stationary sources, the second alternative was chosen for selecting the NO_x emission concentration limit. This approach will achieve the greatest reduction in NO_x emissions from new IC engines.

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TABLE III

SUMMARY OF STATISTICAL ANALYSES OF ALTERNATE EMISSION LIMITS

GAS ENGINES

Alternative	I	II	III
Standard	17	9	11
Percent required to apply less than or equal to 40 percent control	99	50	84
Percent required to do nothing	69	7	18
Percent required to apply more than 40 percent control	1	50	16

DUAL-FUEL ENGINES

Alternative	I	II	III
Standard	9	5	7
Percent required to apply less than or equal to 40 percent control	98	54	87
Percent required to do nothing	62	18	48
Percent required to apply more than 40 percent control	2	46	13

DIESEL ENGINES

Alternative	I	II	III
Standard	11	7	9
Percent required to apply less than or equal to 40 percent control	98	56	86
Percent required to do nothing	50	4	29
Percent required to apply more than 40 percent control	2	44	14

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Selection of limits.—A concentration (ppm) format was selected for the standards. Consequently, the brake-specific NO_x emission limits corresponding to the second alternative for selecting numerical emission limits (i.e., gas – 9 g/hp-hr; dual-fuel – 5 g/hp-hr; diesel – 7 g/hp-hr) must be converted to concentration limits (corrected to 15 percent O_2 on a dry basis). This may be done by dividing the brake-specific volume of NO_x emissions by the brake-specific total exhaust gas volume. Determining the brake-specific volume of NO_x emissions is straight-forward. Determining the brake-specific total exhaust gas volume is more complex, in that the brake-specific exhaust flow and the exhaust gas molecular weight are unknown. Knowing the fuel heating value and composition, the brake-specific fuel consumption, and assuming 15 percent excess air, however, defines these unknowns. (The complete derivation is explained in detail in the Standards Support and Environmental Impact Statement.) Combining these factors leads to the following conversion factor:

$$NO_x = \frac{\left(\frac{10^6}{46}\right) \times (BSNO_x)}{\left(\frac{16.6 + 3.29\,Z}{12.0 + Z}\right) \times (BSFC)}$$

where:
NO_x = NO_x concentration (ppm) corrected to 15 percent O_2.
$BSNO_x$ = Brake-specific NO_x emissions, g/hp-hr.
BSFC = Brake-specific fuel consumption, g/hp-hr.
Z = Hydrogen/Carbon ratio of the fuel.

For natural gas, a hydrogen-to-carbon (H/C) ratio of 3.5 and a lower heat value (LHV) of 20,000 Btu/lb was assumed. Diesel ASTM-2 has a H/C ratio of 1.8 and a LHV of 18,320 Btu/lb.

Applying this conversion factor to the brake-specific emission limits associated with the second alternative for selecting NO_x emissions limits leads to the NO_x concentration emission limits included in the proposed standards:

Engine:	NO_x emission limit
Gas	700 ppm.
Dual-fuel/Diesel	600 ppm.

These emission limits have been rounded upward to the nearest 100 ppm to include a "margin" to allow for source variability. The standard for diesel engines has also been applied to dual-fuel engines. If a separate emission limit has been selected for dual-fuel engines, the corresponding numerical NO_x concentration emission limit would be 400 ppm. Sales of dual-fuel engines, however, have ranged from 17 to 95 units annually over the past five years, with a general trend of decreasing sales. Dual-fuel engines serve the same applications as diesel engines, and new dual-fuel engines will likely operate primarily as diesel engines because of increasingly limited natural gas supplies. Thus, the combining of dual-fuel engines with diesel engines for standards of performance will have little adverse impact and will simplify enforcement of the standards of performance.

The effect of ambient atmospheric conditions on NO_x emissions from large stationary IC engines can be significant. Therefore, to enforce the standards uniformly, NO_x emissions must be determined relative to a reference set of ambient conditions. All existing ambient correction factors were reviewed that could potentially be applied to large stationary IC engines to correct NO_x emissions to standard conditions.

The correction factors that were selected for both spark ignition (SI) and compression ignition (CI) engines are included in the proposed standards. For the compression ignition engines (i.e., diesel and dual-fuel), a single correction factor for both temperature and humididty was selected. For spark ignition engines (i.e., gas), separate correction factors were selected for humidity and temperature, and measured NO_x emissions are corrected to reference ambient conditions by multiplying these two factors together. No correction factor was selected for changes in ambient pressure because no generalized relationship could be determined from the very limited data that are available. These correction factors represent the general effects of ambient temperature and relative humidity on NO_x emissions, and will be used to adjust measured NO_x emissions during any performance test to determine compliance with the numerical emission limit.

Since the recommended factors may not be applicable to certain engine models, as an alternative to the use of these correction factors, engine manufacturers, owners, or operators may elect to develop their own ambient correction factors. All such correction factors, however, must be substantiated with data and then approved by EPA for use in determining compliance with NO_x emission limits. The ambient correction factor will be applied to all performance tests, not only those in which the use of such factors would reduce measured emission levels.

As discussed in "Standards Support and Environmental Impact Statement: Proposed Standards of Performance for Stationary Gas Turbines," EPA-450/2-77-017a, the contribution to NO_x emissions by the conversion of fuel-bound nitrogen in heavy fuel to NO_x can be significant for stationary gas turbines. The organic NO_x contribution to total gas turbine NO_x emissions is complicated by the fact that the percentage of fuel-bound nitrogen converted to NO_x decreases as the fuel-bound nitrogen level increases. Below a fuel-bound nitrogen level of about 0.05 percent, essentially 100 percent of the fuel-bound nitrogen is converted to NO_x. Above a fuel-bound nitrogen level of about 0.4 percent, only about 40 percent is converted to NO_x.

As discussed in the Standards Support and Environmental Impact Statement, Volume I for Stationary Gas Turbines, assuming a fuel with 0.25 percent weight fuel-bound nitrogen (which allows approximately 50 percent availablility of domestic heavy fuel oil), controlled NO_x emissions would increase by about 50 ppm due to the contribution to NO_x emissions of fuel-bound nitrogen. In gas turbines, this contribution was significant when compared to the proposed emission limit of 75 ppm. However, for large IC engines, the contribution of fuel-bound nitrogen to NO_x emissions is likely to be small (approximately 10 percent). Sales of IC engines firing heavy fuels is insignificant and not expected to increase in the near future. Given that the emission limits have been rounded upward to the nearest 100 ppm and the potential contribution of fuel-bound nitrogen to NO_x emissions is very small, no allowance has been included for the fuel-bound nitrogen content of the fuel in determining compliance with the standards of performance.

Selection of Compliance Time Frame

Manufacturers of large-bore IC engines are generally committed to a particular design approach and, therefore, conduct extensive research, development, and prototype testing before releasing a new engine model for sale. Consequently, these manufacturers will require some period of time to alter or reoptimize and test IC engines to meet standards of performance. The estimated time span between the decision by a manufacturer to control NO_x emissions from an engine model and start of production of the first controlled engine is about 15 months for any of the four demonstrated emission control techniques. With their present facilities, however, testing can typically be conducted on only two to three engine models at a time. Since most manufacturers produce a number of engine models, additional time is required before standards of performance become effective. In addition, a number of manufacturers produce their most popular engine models at a fairly steady rate of production and satisfy fluctuating demands from inventory. Consequently, additional time in necessary to allow manufacturers to sell their current inventory of uncontrolled IC engines before they must comply with standards of performance.

It is estimated that about 30 months delay in the applicability date of the standard is appropriate to allow manufacturers time to comply with the proposed standards of performance. In addition, in light of the stringency of the standards (i.e., many engine models will have to reduce NO_x emissions by more than 40 percent) this time period provides the flexibility for manufacturers to develop and use combinations of the control techniques upon which the standards are based or other control techniques. Consequently, 30 months from today's date is selected as the delay period for implementation of these standards on large stationary IC engines.

Selection of Monitoring Requirements

To provide a means for enforcement personnel to ensure that an emission control system installed to comply with standards of performance is properly operated and maintained, monitoring requirements are generally included in standards of performance. For stationary IC engines, the most straightforward means of ensuring proper operation and maintenance would be to monitor NO_x emissions released to the atmosphere.

Installed costs, however, for continuous monitors are approximately $25,000. Thus the cost of continuous NO_x emission monitoring is considered unreasonable for IC engines since most large stationary IC engines cost from $50,000 to $3,000,000 (i.e., 1000 hp gas production engine and 20,000 hp electrical generation engine).

A more simple and less costly method of monitoring is measuring various engine operating parameters related to NO_x emissions. Consequently, monitoring of exhaust gas temperature was considered since this parameter could be measured just after the combustion process during which NO_x is formed. However, a thorough investigation of this approach showed no simple correlation between NO_x emission and exhaust gas temperature.

A qualitative estimate of NO_x emissions, however, can be developed by measuring several engine operating parameters simultaneously, such as spark ignition or fuel injector timing, engine speed, and a number of other parameters. These parameters are typically measured at most installations and thus should not impose an additional cost impact. For these reasons, the emission monitoring requirements included in the proposed standards of performance require monitoring various engine operating parameters.

For diesel and dual-fuel engines, the engine parameters to be monitored are: (1) Intake manifold temperature; (2) intake manifold pressure; (3) rack position; (4) fuel injector timing; and (5) engine speed. Gas engines would require monitoring of (1) intake manifold temperature; (2) intake manifold pressure; (3) fuel header pressure; (4) spark timing; and (5) engine speed.

Another parameter that could be monitored for gas engines is the fuel heat value, since it can affect NO_x emissions significantly. Because of the high costs of a fuel heating value monitor, and the fact that many facilities can obtain the lower heating value directly from the gas supplier, monitoring of this parameter would not be required.

The operating ranges for each parameter over which the engine could operate and in which the engine could comply with the NO_x emission limit would be determined during the performance test. Once established, these parameters would be monitored to ensure proper operation and maintenance of the emission control techniques employed to comply with the standards of performance.

For facilities having an operator present every day these operating parameters would be recorded daily. For remote facilities, where an operator is not present every day, these operating parameters would be recorded weekly. The owner/operator would record the parameters and, if these parameters include values outside the operating ranges determined during the performance test, a report would be submitted to the Administrator on a quarterly basis identifying these periods as excess emissions. Each excess emission report would include the operating ranges for each parameter as determined during the performance test, the monitored values for each parameter, and the ambient air conditions.

Selection of Performance Test Method

A performance test method is required to determine whether an engine complies with the standards of performance. Reference Method 20, "Determination of Nitrogen Oxides, Sulfur Dioxide, and Oxygen emissions from Stationary Gas Turbines," which was proposed in the October 3, 1977 Federal Register, is proposed as the performance test method for IC engines. Reference Method 20 has been shown to provide valid results. Consequently, rather than developing a totally new reference test method, Reference Method 20 would be modified for use on IC engines.

The changes and additions to Reference Method 20 required to make it applicable for testing of internal combustion engines include (by section):

1. *Principle and Applicability.* Sulfur dioxide measurements are not applicable for internal combustion engine testing.

6.1 Selection of a sampling site and the minimum number of traverse points.

6.11 Select a sampling site located at least five stack diameters downstream of any turbocharger exhaust, crossover junction, or recirculation take-offs and upstream of an dilution air inlet. Locate the sample site no closer than one meter or three stack diameters (whichever is less) upstream of the gas discharge to the atmosphere.

6.1.2 A preliminary O_2 traverse is not necessary.

6.1.2.2 Cross-sectional layout and location of traverse points use a minimum of three sample points located at positions of 16.7, 50 and 83.3 percent of the stack diameter.

6.2.1 Record the data required on the engine operation record on Figure 20.7 of Reference Method 20. In addition, record (a) the intake manifold pressure; (b) the intake manifold temperature; (c) rack position; (d) engine speed; and (e) injector or spark fuming. (The water or steam injection rate is not applicable to internal combustion engines.)

NO_x emissions measured by Reference Method 20 will be affected by ambient atmospheric conditions. Consequently, measured NO_x emissions would be adjusted during any performance test by the ambient condition correction factors discussed earlier, or by custom correction factors approved for use by EPA.

The performance test may be performed either by the manufacturer or at the actual user operating site. If the test is performed at the manufacturer's facility, compliance with that performance test will be sufficient proof of compliance by the user as long as the engine operating parameters are not varied during user operation from the settings under which testing was done.

Public Hearing

A public hearing will be held to discuss these proposed standards in accordance with section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given in the ADDRESSES Section of this preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement with EPA before, during, or within 30 days after the hearing. Written statement should be addressed to Mr. Jack R. Farmer (see ADDRESSES Section).

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The principal purposes of the docket are (1) to allow interested parties to identify and locate documents so that they can intelligently and effectively participate in the rulemaking process, and (2) to serve as the record for judicial review. The docket requirement is discussed in section 307(d) of the Clean Air Act.

Miscellaneous

As prescribed by Section 111 of the Act, this proposal is accompanied by the Administrator's determination that emissions from stationary IC engines contribute to air pollution which causes or contributes to the endangerment of public health or welfare, and by publication of this determination in this issue of the Federal Register. In accordance with section 117 of the Act, publication of these standards was preceded by consultation with appropriate advisory committees, independent experts, and federal department and agencies. The Administrator welcomes comments on all aspects of the proposed regulations, including the designation of stationary IC engines as a significant contributor to air pollution which causes or contributes to the endangerment of public health or welfare, economic and technological issues, monitoring requirements and the proposed test method.

Comments are specifically invited on the severity of the economic and environmental impact of the proposed standards on stationary naturally aspirated carbureted-gas IC engines since some parties have expressed objection to applying the proposed standards to these engines. Comments are also invited on the selection of rotary engines for control by standards of performance. These engines were included because they are expected to be contributors to NO_x emissions from stationary sources and can be controlled by demonstrated NO_x emission control techniques. Any comments submitted to the Administrator on these issues, however, should contain specific information and data pertinent to an evaluation of the magnitude of this impact, its severity, and its consequences.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect:

> The degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [section 111(a)(1)].

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be seclected as the basis of standards of performance because of costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act may require the imposition of a more stringent emission standard emission in several situations.

For example, applicable costs do not necessarily play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources located in nonattainment areas (i.e., those areas where statutorily mandated health and welfare standards are being violated). In this respect, section 173 of the Act requires that new or modified sources constructed in an area which exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3). The statute defines LAER as that rate of emissions which reflects:

> (A) The most stringent emission limitation which is contained in the implementation plan of any state for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable or
>
> (B) The most stringent emission limitation which is acheved in practice by such class or category of source, whichever is more stringent.

In no event can the emission rate exceed any applicable new source performance standard.

A similar situation may arise under the prevention-of-significant-deterioration-of-air-quality provisions of the Act. These provisions require that certain sources employ "best available control technology" (BACT) as defined in section 169(3) for all pollutants regulated under the Act. Best available control technology must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all cases, State Implementation Plans (SIP's) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of NAAQS designed to protect public health and welfare. For this purpose, SIP's must in some cases require greater emission reduction than those required by standards of performance for new sources.

Finally, states are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Under EPA's "new" sunset policy for reporting requirements in regulations, the reporting requirements in this regulation will automatically expire five years from the date of promulgation unless EPA takes affirmative action to extend them.

EPA will review this regulation four years from the date of promulgation. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, and improvements in emissions control technology.

An economic impact assessment has been prepared as required under section 317 of the Act and is included in the Standards Support and Environmental Impact Statement.

Dated: July 11, 1979.

Douglas M. Costle,

Administrator.

It is proposed to amend Part 60 of Chapter I, Title 40 of the Code of Federal Regulations as follows:

1. By adding Subpart FF as follows:

Subpart FF—Standards of Performance for Stationary Internal Combustion Engines

Sec.

60.320 Applicability and designation of affected facility.

60.321 Definitions.

60.322 Standards for nitrogen oxides.

60.323 Monitoring of operations.

60.324 Test methods and procedures.

Authority: Secs. 111 and 301(a) of the Clean Air Act, as amended, (42 U.S.C. 1857c-7, 1857g(a)), and additional authority as noted below.

Subpart FF—Standards of Performance for Stationary Internal Combustion Engines

§ 60.320 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities which commence construction beginning 30 months from today's date:

(a) All gas engines that are either greater than 350 cubic inch displacement per cylinder or equal to or greater than 8 cylinders and greater than 240 cubic inch displacement per cylinder.

(b) All diesel or dual-fuel engines that are greater than 560 cubic inch displacement per cylinder.

(c) All rotary engines that are greater than 1500 cubic inch displacement per rotor.

§ 60.321 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in subpart A of this part.

(a) "Stationary internal combustion engine" means any internal combution engine, except gas turbines, that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) "Emergency standby engine" means any stationary internal combustion engine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable during an emergency situation.

(c) "Reference ambient conditions" means standard air temperature (29.4°C, or 85°F), humidity (17 grams H_2O/kg dry air, or 75 grains H_2O/lb dry air), and pressure (101.3 kilopascals, or 29.92 in. Hg.).

(d) "Peak load" means operation at 100 percent of the manufacturer's design capacity.

(e) "Diesel engine" means any stationary internal combustion engine burning a liquid fuel.

(f) "Gas enine" means any stationary internal combustion engine burning a gaseous fuel.

(g) "Dual-fuel engine" means any stationary internal combustion engine that is burning liquid and gaseous fuel simultaneously.

(h) "Unmanned engine" means any stationary internal combustion engine installed and operating at a location which does not have an operator regularly present at the site for some portion of a 24-hour day.

(i) "Non-remote operation" means any engine installed and operating at a loction which has an operator regularly present at the site for some portion of a 24-hour day.

(j) "Brake-specific fuel consumption" means fuel input heat rate, based on the lower heating value of the fuel, expressed on the basis of power output (i.e., (kJ/w-hr).

(k) "Weekly basis" means at seven day intervals.

(l) "Daily basis" means at 24 hours intervals.

(m) "Rotary engine" means any Wankel type engine where energy from the combustion of fuel is converted directly to rotary motions instead of reciprocating motion.

(n) "Displacement per rotor" means the volume contained in the chamber of a rotary engine between one flank of the rotor and the housing at the instant the inlet port is closed.

§ 60.322 Standards for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere, except as provided in paragraphs (b) and (c) of this section—

(1) From any gas engine, with a brake-specific fuel consumption at peak load more than or equal to 10.2 kilojoules/watt-hour any gases which contain nitrogen oxides in excess of 700 parts per million volume, corrected to 15 percent oxygen on a dry basis.

(2) From any diesel or dual-fuel engine with a brake-specific fuel consumption at peak load more than or equal to 10.2 kilojoules/watt-hour any gases which contain nitrogen oxides in excess of 600 parts per million volume, corrected to 15 percent oxygen on a dry basis.

(3) From any stationary internal combustion engine with a brake-specific fuel consumption at peak load of less than or equal to 10.2 kilojoules/watt-hour any gases which contain nitrogen oxides in excess of:

(i) $STD = 700 \frac{10.2}{Y}$ for any gas engine,

(ii) $STD = 600 \frac{10.2}{Y}$ for any diesel or dual-fuel engine

where:

STD = allowable NO_x emissions (parts-per-million volume corrected to 15 percent oxygen on a dry basis).

Y = manufacturer's rated brake-specific fuel consumption at peak load (kilojoules per watt-hour) or owner/operator's brake-specific fuel consumption at peak load as determined in the field.

(b) All one and two cylinder reciprocating gas engines are exempt from paragraph (a) of this section.

(c) Emergency standby engines are exempt from paragraph (a) of this section.

§ 60.323 Monitoring of operations.

(a) The owner or operator of any stationary internal combustion engine, subject to the provisions of this subpart must, on a weekly basis for unmanned engines and on a daily basis for manned engines, monitor and record the following parameters. All monitoring systems shall be accurate to within five percent and shall be approved by the Administrator.

(1) For diesel and dual-fuel engines:

(i) Intake manifold temperature

(ii) Intake manifold pressure

(iii) Engine speed

(iv) Diesel rack position (fuel flow)

(v) Injector timing

(2) For gas engines:

(i) Intake manifold temperature

(ii) Intake manifold pressure

(iii) Fuel header pressure

(iv) Engine speed

(v) Spark ignition timing

(b) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as any daily (for manned engines) or weekly (for unmanned engines) period during which any one of the parameters specified under paragraph (a) of this section falls outside the range identified for that parameter udner § 60.324(a)(3). Each excess emission report shall include the range identified for each operating parameter under § 60.324(a)(4), the monitored value for each operating parameter specified under § 60.323(a), the ambient air conditions during the period of excess emissions, and any graphs and/or figures developed under § 60.324(a)(4)

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 1857c-9))

§ 60.324 Test methods and procedures.

The reference methods in Appendix A to this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.322 as follows:

(a) Reference Method 20 for the concentration of nitrogen oxides and oxygen. The span for the nitrogen oxides analyzer used in this method shall be 1500 ppm.

(1) The following changes and additions (by section) to Reference Method procedures should be followed when determining compliance with § 60.322:

1. *Principle and Applicability.* Sulfur dioxide measurements are not applicable for internal combustion engine testing.

6.1 Selection of a sampling site and the minimum number of traverse points.

6.11 Select a sampling site located at least five stack diameters downstream of any turbocharger exhaust, crossover junction, or recirculation take-offs and upstream of any dilution air inlet. Locate the sample site no closer than one meter or three stack diameters (whichever is less) upstream of the gas discharge to the atmosphere.

6.1.2 a preliminary O_2 traverse is not necessary.

6.2 Cross-sectional layout and location of traverse points. Use a minimum of three sample points located at positions of 16.7, 50 and 83.3 percent of the stack diameter.

6.2.1 Record the data required on the engine operation record on Figure 20.7 of Reference Method 20. In addition, record (a) the intake manifold pressure; (b) the intake manifold temperature; (c) rack position, fuel header pressure or carburetor position; (d) engine speed; and (e) injector or spark timing. (The water or steam injection rate is not applicable to internal combustion engines.)

(2) The nitrogen oxides emission level measured by Reference Method 20 shall be adjusted to reference ambient conditions by the following ambient condition correction factors:

NO_x corrected = (K) NO_x observed

where K is determined as follows:

Fuel	Correction Factor
Diesel and Dual-Fuel	$K = 1/(1 + 0.00235(H - 75) + 0.00220\ (T - 85))$
Gas	$K = (K_H)\ (K_T)$ $K_H = 0.844 + 0.151\ (\frac{H}{100}) + 0.075\ (\frac{H}{100})^2$ $K_T = 1 - (T - 85)(0.0135)$

where:

H = observed humidity, grains H_2O/lb dry air

T = observed inlet air temperature, °F

The adjusted NO_x emission level shall be used to determine compliance with § 60.322.

(3) Manufacturers, owners, or operators may develop custom ambient correction factors in terms of ambient air temperature and/or pressure, and/or humidity to adjust the nitrogen oxide emission level measured by the performance test to reference ambient conditions. These correction factors must be substantiated with data and must be approved by the Administrator before they can be used to determine compliance with § 60.322. Notices of approval of custom ambient condition correction factors will be published in the Federal Register.

(4) Testing shall be conducted and ranges identified for each parameter specified under § 60.323(a) over which the numerical emission limits included under § 60.322 are not exceeded. This will be accomplished by measuring NO_x emissions, using Reference Method 20, and these parameters at four points over the normal load range of the internal combustion engine, including the minimum and maximum points in the range if the stationary internal combustion engine will be operated over a range of load conditions.

(b) ASTM D-2382 shall be used to determine the lower heating value of liquid fuels and ASTM D-1826 shall be used to determine the lower heating value of gaseous fuels.

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 1857c-9))

[FR Doc. 79-22224 Filed 7-20-79; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

[FRL 1099-6]

Air Pollution Prevention and Control; Addition to the List of Categories of Stationary Sources

Section 111 of the Clean Air Act (42 U.S.C. 1857c-6) directs the Administrator of the Environmental Protection Agency to publish, and from time to time revise, a list of categories of stationary sources which he determines may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare. Within 120 days after the inclusion of a category of stationary sources in such list, the Administrator is required to propose regulations establishing standards of performance for new and modified sources within such category. At present standards of performance for 27 categories of sources have been promulgated.

The Administrator, after evaluating available information, has determined that stationary internal combustion engines are an additional category of stationary sources which meets the above requirements. The basis for this determination is discussed in the preamble to the proposed regulation that is published elsewhere in this issue of the Federal Register. Evaluation of other stationary source categories is in progress, and the list will be revised from time to time as the Administrator deems appropriate. Stationary internal combustion engines are included on the proposed NSPS priority list (published August 31, 1978) required by section 111(f)(1), but since the priority list is not final, stationary internal combustion engines are also being listed as indicated below at this time. Once the priority list is promulgated, all source categories on the promulgated list are considered listed under section 111(b)(1)(A), and separate listings such as this will not be made for those source categories.

Accordingly, notice is given that the Administrator, pursuant to section 111(b)(1)(A) of the Act, and after consultation with appropriate advisory committees, experts and Federal departments and agencies in accordance with section 117(f) of the Act, effective July 23, 1979 amends the list of categories of stationary sources to read as follows:

List of Categories of Stationary Sources and Corresponding Affected Facilities

* * * * *

Source Category

* * * * *

Affected Facilities

Internal combustion engines

Proposed standards of performance applicable to the above source category appear elsewhere in this issue of the Federal Register.

Dated: July 11, 1979.

Douglas M. Costle,

Administrator.

[FR Doc. 79-22225 Filed 7-20-79; 8:45 am]

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federal register

Monday
July 23, 1979

Part III

Department of Energy

Economic Regulatory Administration

Powerplant and Industrial Fuel Use Act of 1978; Existing Facilities: Criteria for Petitions for Exemptions; Findings and Procedures for Prohibition Orders; Amendments to Previously Issued Rules

DEPARTMENT OF ENERGY

Economic Regulatory Administration

10 CFR Parts 500, 501, 503, 504, 505 and 506

[Docket No. ERA-R-78-19G]

Powerplant and Industrial Fuel Use Act of 1978; Existing Facilities: Criteria for Petitions for Exemptions; Findings and Procedures for Prohibition Orders; Amendments to Previously Issued Rules

AGENCY: Economic Regulatory Administration, Department of Energy.

ACTION: Interim Rule; extension of comment period on certain other interim rules.

SUMMARY: The Economic Regulatory Administration (ERA) of the Department of Energy (DOE) is issuing this interim rule to implement provisions of the Powerplant and Industrial Fuel Use Act of 1978, Pub. L. 95-620, (FUA) which (1) prohibit or restrict the use of natural gas by certain existing electric powerplants and (2) grant ERA the authority to issue rules and orders prohibiting or restricting the use of petroleum or natural gas, or both, by existing electric powerplants and major fuel-burning installations which ERA finds are capable of burning an alternate fuel. These interim rules establish the criteria upon which owners and operators of powerplants and installations may petition for exemption from applicable prohibitions, and the procedures and criteria pursuant to which ERA will issue orders prohibiting or restricting the use of petroleum and natural gas. ERA is also amending, in this rulemaking, certain provisions contained in the Interim Rules published in the Federal Register on May 15, 1979 (44 FR 28530), and May 17, 1979 (44 FR 28950), and is soliciting additional comments on certain issues which relate both to new and to existing facilities.

DATES: These interim rules shall become effective August 20, 1979. Written comments are due by 4:30 p.m. September 15, 1979. No additional public hearings will be held. However, before issuing these rules in final form, ERA will consider all written comments submitted prior to September 15, 1979.

ERA hereby also gives notice of the extension of the period for written comments from August 15, 1979, to September 15, 1979, for the following effective interim rules which implement the Act:

Prohibition Against Increased Use of Petroleum by Existing Electric Powerplants (Docket No. ERA-R-78-19C) issued on May 8, 1979 (44 FR 28594, May 15, 1979);

Definitions and Administrative Procedures and Sanctions (Docket No. ERA-R-78-19D) issued on May 8, 1979 (44 FR 28530, May 15, 1979);

Criteria for Petition for Exemption from Prohibitions of the Act (Docket No. ERA-R-78-19E) issued on May 8, 1979 (44 FR 28950, May 17, 1979); and

Electric utility System Compliance Option (Docket No. ERA-R-78-19F), issued on June 12, 1979 (44 FR 36002, June 20, 1979).

ADDRESSES: All comments should be addressed to Public Hearing Management (Docket No. ERA-R-78-19G), U.S. Department of Energy, Room 2313, 2000 M Street, NW., Washington, D.C. 20461.

FOR FURTHER INFORMATION CONTACT:
William L. Webb (Office of Public Information), Economic Regulatory Administration, U.S. Department of Energy, 2000 M Street, NW., Room B-110, Washington, D.C. 20461, (202) 634-2170.
Stephen M. Stern (Regulations and Emergency Planning), Economic Regulatory Administration, U.S. Department of Energy, 2000 M Street, NW., Room 2130-C, Washington, D.C. 20461, (202) 254-3987.
Robert L. Davies (Fuels Regulations—Program Office), Economic Regulatory Administration, U.S. Department of Energy, 2000 M Street, NW., Room 6128-I, Washington, D.C. 20461, (202) 254-7442.
James Heffernan (Office of General Counsel), U.S. Department of Energy, 12th and Pennsylvania Avenue, NW., Room 7136, Washington, D.C. 20461, (202) 633-8814.

SUPPLEMENTARY INFORMATION:

I. Background and Extended Comment Period.

The Powerplant and Industrial Fuel Use Act of 1978 (FUA or the Act) requires the establishment by ERA of a program for the expanded use, consistent with applicable environmental requirements, of coal and other alternate fuels and primary energy sources for new and existing electric powerplants and major fuel burning installations.

The following is a list of notices and rules previously issued under the Act, exclusive of notices related to petitions received under FUA.

	Notice of rule	
	Date issued	FEDERAL REGISTER citation
Notice of availability, draft EIS	November 5, 1978	43 FR 52515 (Nov. 13, 1978)
Proposed rules pertaining to "new" facilities	November 9, 1978	43 FR 53974 (Nov. 17, 1978)
Proposed rules pertaining to "transitional" facilities	November 16, 1978	43 FR 54912 (Nov. 22, 1978)
Early filing procedure under Section 902 of FUA	November 17, 1978	43 FR 55449 (Nov. 28, 1978)
Clarification/proposed rules pertaining to "transitional" facilities	November 24, 1978	43 FR 55745 (Nov. 29, 1978)
Proposed forms for "transitional" facilities	November 27, 1978	43 FR 56703 (Dec. 4, 1978)
Transitional facilities: Notice of additional hearing on interim rule	December 11, 1978	43 FR 58092 (Dec. 12, 1978)
Hearing on interim transitional facility rule	December 22, 1978	44 FR 761 (Jan. 3, 1979)

	Notice or rule: Date issued	Notice or rule: FEDERAL REGISTER citation
Notice of procedures by which ESECA Prohibition Order recipients may elect to be covered under FUA	December 28, 1978	44 FR 1443 (Jan. 5, 1979)
Draft EIS/Hearing and comment period	January 2, 1979	44 FR 2004 (Jan. 23, 1979)
Proposed special rule for a temporary public interest exemption for the use of natural gas	January 3, 1979	44 FR 1694 (Jan. 5, 1979)
Notice of hearings on "new" facilities; extension of public comment period	January 12, 1979	44 FR 3721 (Jan 18, 1979)
Proposed rule Powerplant design capacity	January 19, 1979	44 FR 4500 (Jan. 22, 1979)
Proposed rules pertaining to "existing" facilities (including § 405 of FUA); and extending comment period	January 23, 1979	44 FR 5808 (Jan 23, 1979)
Notice of Hearings on "new" and existing facilities	January 23, 1979	44 FR 5808 (Jan. 23, 1979)
Proposed guidelines for Environmental Reports	January 25, 1979	44 FR 6177 (Jan. 31, 1979)
Proposed forms for "new" facilities	January 31, 1979	44 FR 9053 (Feb. 12, 1979)
Proposed rule—sale and direct industrial use of natural gas for outdoor lighting.	February 7, 1979	44 FR 8570 (Feb. 13, 1979)
Interim Rule on powerplant design capacity	February 9, 1979)	44 FR 10368 (Feb. 20, 1979)
Symposium—hearing on proposed rules	February 13, 1979	44 FR 10390 (Feb 20, 1979)
Extension of public comment for "new" facilities; and proposed forms	March 1, 1979	44 FR 12227, 12236 (Mar 6, 1979)
Revised interim rule—"transitional" facilities	March 15, 1979	44 FR 17464 (Mar 21, 1979)
Notice of intent to issue interim rules to implement FUA	March 26, 1979	44 FR 19427 (Apr 3, 1979)
Powerplant design capacity Correction	March 28, 1979	44 FR 20078 (April 4, 1979)
Availability Final EIS	April 2, 1979	44 FR 20745 (April 6, 1979)
Final rule—special rule for temporary public interest exemption for use of natural gas	April 4, 1979	44 FR 21230 (Apr 9, 1979)
Notice of OMB clearance of regulations in Part 515	April 30, 1979	44 FR 25192 (Apr 30, 1979)
Final rule—sale and direct industrial use of natural gas for outdoor lighting.	May 3, 1979	44 FR 27606 (May 10, 1979)
Interim rule—definitions and administrative procedures and sanctions	May 8, 1979	44 FR 28530 (May 15, 1979)
Interim rule—prohibition against increased use of petroleum by existing electric powerplants	May 8, 1979	44 FR 28594 (May 15, 1979)
Interim rule—"new" facilities. criteria for petition for exemption from prohibitions of the Act	May 8, 1979	44 FR 28958 (May 17, 1979)
Notice to Federal Agencies of FUA	May 24, 1979	44 FR 28958 (May 31, 1979)
Notice of OMB clearance of regulations in Part 508	May 30, 1979	44 FR 32199 (June 5, 1979)
Interim rule—System Compliance Option	June 12, 1979	44 FR 36002 (June 20, 1979)

Parts 504 and 506 of these interim rules set forth the criteria that must be met to establish eligibility for a temporary or permanent exemption under Title III of FUA and the criteria ERA will use in issuing prohibition orders. Subpart E of Part 501 has been amended to include the procedures ERA will use to issue prohibition orders under Title III of FUA.

The period for submission of written comments on this interim rule commences on the date this interim rule is issued and extends until September 15, 1979. ERA invites all interested persons to participate in these further proceedings by submitting any written information, views or arguments to U.S. Department of Energy, Public Hearing Management, Room 2313, 2000 M Street, NW., Washington, D.C. 20461. All submissions should be identified on the outside of the envelope and on the documents contained therein with the designation, "Existing Facility Regulations" (Docket No. ERA-R-78-19G). You should submit 15 copies. All comments received will be available for public inspection in the DOE Reading Room (Rm. GS-152), James Forrestal Building, 1000 Independence Avenue, SW., Washington, D.C. We will consider all comments received by September 15, 1979, and incorporate these into the record of the administrative proceedings for Parts 504 and 506, and Parts 500, 501, 503, or 505, where appropriate.

With regard to the prohibitions on natural gas use by existing electric powerplants imposed by Section 301(a) of FUA, ERA will receive petitions for exemptions in accordance with the procedures and definitions set forth in § 500.2 and Part 501. ERA's determinations with regard to exemption petitions shall be made upon the basis of the standards and criteria set forth in Parts 504 and 506 of this Interim Rule or upon the provisions of those Parts, as subsequently revised, where the application of a modification of a particular rule would result in a more favorable disposition of a particular petition.

II. Analysis of Comments on Existing Facility Rules

In the Preamble to the Proposed Rules published on January 29, 1979, ERA specifically solicited comments on such issues as: the various exemptions, the Fuels Decision Report, the cost calculations, the pre-order conference and the findings for issuing prohibition orders prohibiting natural gas and petroleum.

ERA received a number of written and oral comments on these issues as well as comments on many issues not specifically identified in the Preamble to the proposed rules. In order to facilitate an orderly discussion of these comments and ERA's specific responses to them, each will be discussed in the order in which they appear in this interim rule. Except in a few instances, if ERA has already addressed an issue in a previously published Federal Register notice, ERA will not readdress the same issue here. Thus, issues related to the following exemptions and findings are not discussed here but were addressed in the preamble to the interim rule for new facilities published on May 17 (44 FR 28950):

Lack of alternate fuel supply (§§ 504.21, 504.31, 504.21, and 506.31)
Environmental requirements (§§ 504.23, 504.33, 506.23, 506.33)
Future use of synthetic fuel (§ 504.24 and § 506.24)
Temporary public interest exemption (§ 504.26 and § 506.27)
Temporary reliability exemption (§ 504.28)
State or local requirements (§ 504.34 and § 506.34)
Permanent mixtures exemption (§ 504.36 and § 506.36)
Emergency purposes (§ 504.37 and § 506.37)
Intermediate load powerplants (§ 504.39)
Scheduled equipment outages (§ 506.39)
Use of fluidized bed combustion (§ 506.15)

A. Prohibition Order Administrative Procedures (§ 501.51 and § 501.52)

Comments. Some commenters urged that ERA hold a pre-order conference prior to issuing any proposed prohibition order. ERA has provided that such conferences may be held at its discretion, and it is anticipated that whenever feasible, pre-order conferences will be convened.

Other commenters recommended that ERA provide an automatic stay of any Prohibition Order pending ERA action on a petition for an exemption. With regard to this comment see "Description of Prohibition Order Proceedings," set forth below.

It was also suggested that ERA provide for an Environmental Impact Statement at the proposal stage of a prohibition order proceeding. ERA will determine on a case-by-case basis whether an Environmental Impact Statement is required, and will comply to the fullest with the provisions of the National Environmental Policy Act of 1969.

Description of Prohibition Order Proceedings. After ERA has performed its initial information gathering with respect to the question of technical capability to burn alternate fuels, ERA may, in its discretion, inform the prospective proposed order recipient that it is considering a proposed prohibition order, and invite informal discussion concerning issuance of any such proposed order.

If, following this discussion, ERA still believes that a proposed order may be warranted, and finds that the facility in question has or had the technical capability of using an alternate fuel as its primary energy source, ERA will publish a finding to that effect and a proposed prohibition order in the Federal Register. In accordance with Section 301(b) of FUA, the proposed order will not contain, at this point in the proceeding, the other findings that ERA must make before a final prohibition order can be issued.

Upon issuance of the proposed order, a 3-month comment period will commence, during which the recipient of the proposed prohibition order will be given an opportunity to challenge ERA's initial finding of technical capability, to present evidence relevant to financial feasibility, and to come forward with evidence bearing upon the other findings ultimately required to be made by ERA prior to the issuance of a final prohibition order. (While the burden of coming forward with evidence regarding the other findings is, at this stage of the proceeding, on the respondent, since the facts with respect to the latter findings lie peculiarly in his knowledge, the ultimate burden of persuasion remains with ERA.) In his written submissions the order recipient will also be asked to identify, but not to demonstrate its entitlement to, possible bases for exemption. During this period, the order recipient may request a conference with ERA. Except in limited circumstances specified in the rule, a proposed order recipient will not be allowed to present evidence relating to the findings in subsequent steps of the proceeding that he did not raise in his written submission during this 3-month period.

Subsequent to the close of the initial comment period, ERA will express its intention by notice published in the Federal Register and sent to the recipient whether to continue the prohibition order proceedings. Should ERA decide to proceed, a second 3-month period commences, during which the recipient of the proposed order may submit written evidence of his qualification for an exemption which it wishes to present as a defense to issuance of a final prohibition order.

Except in limited circumstances specified in the rule, a proposed order recipient will not be allowed to contest issuance of a final prohibition order upon the basis of evidence relating to an exemption which it did not present during the second three month period. In attempting to demonstrate qualification for an exemption prior to issuance of a final order, the proposed order recipient need only consider the alternate fuel or fuels with reference to which ERA proposes to make the required findings.

If a respondent does not avail himself of this opportunity to demonstrate that he qualifies for an exemption, he may, after issuance of a final prohibition order, petition for an exemption from the applicable prohibitions of the order as any other petitioner for an exemption. After issuance of a final prohibition order, the petitioner would have to analyze all available alternate fuels and submit a Fuels Decision Report where such anaylsis and submission are required by the exemption being sought. During the pendency of the exemption proceeding, the prohibitions of the final prohibition order would ordinarily be in effect, just as any other effective prohibitions under the Act remain in effect during the pendency of exemption proceedings.

Some commenters suggested that the opportunity to defeat issuance of a prohibition order by demonstrating qualification for exemption should be identical to that provided to a recipient of a proposed prohibition by rule. Under FUA, a prohibition by rule is stayed pending resolution, including judicial review, if respondent petitions for an exemption within 60 days after the rule is published.

Such commenters argued that a proposed order recipient should not have to incur the burden of preparing an exemption request until it is certain that ERA is going to make the required findings and issue a final order—in other words, until after a hearing on the required findings. Only at that point would the sequence of submission, comment and hearing on the exemption begin, during which time the prohibition order would be stayed.

Certainly the statute does not require such elongated procedures in the case of prohibitions by order. The provisions governing prohibition orders make no reference to such procedures, in clear contrast to the provisions governing rules. The exemption showing of a proposed order recipient is instead in the nature of an affirmative defense. Additionally, until a final order is issued, no prohibition is yet in effect which may be stayed.

We believe that the statutory distinction should as a matter of policy be preserved. A proceeding looking toward a prohibition by rule will, by its nature, be a multi-party, multi-unit proceeding, as to which Congress evidently considered it desirable to defer consideration of specific exemption requests until after completion of the proceeding. The delays and multiplication of hearings that the rule sequence entails do not seem warranted in the case of a prohibition order proceeding which, from the beginning, will be focused upon a particular unit, or a very small number of units owned or operated by the same person.

Moreover, under this interim rule, a proposed order recipient will not have to prepare its exemption materials unless and until ERA reaffirms its decision to seek a prohibition order after consideration of the recipient's submissions on all of the required findings. After such a reaffirmation, the recipient will be preparing exemption materials in the face of an agency decision that is considerably more than a preliminary decision based on unilateral inquiry. The interim rule is thus a reasonable accommodation of the interest in avoiding unnecessary private and public burdens and the interest in reasonable expedition in pursuit of the Act's urgent goals.

After the close of the 3-month period in which to demonstrate qualification for an exemption, if ERA still intends to seek a prohibition order, ERA's staff will make available its Tentative Staff Decision and provide a period of no less than 45 days for interested persons to request a public hearing in accordance with Section 501.33. At the hearing, interested persons will have the opportunity to question the parties about ERA's case for the findings it is required to make, the proposed order recipient's showing on exemptions and rebuttal of ERA's findings, and ERA's rebuttal to any showing of qualification for exemption.

After the hearing and comment period closes, if ERA still believes it is warranted, a final prohibition order will be issued.

B. ERA Findings for Issuing Orders Prohibiting Use of Natural Gas and Petroleum (Parts 504 and 506)

Prior to issuing a final order under Sections 301(b) or 302(a) of the Act prohibiting a powerplant or installation from using petroleum or natural gas as a primary energy source, ERA must find that based on substantial evidence: the facility has or previously had the technical capability to use an alternate fuel; the facility currently has such capability or, if it previously had such capability could have it again without substantial physical modification or substantial derating; and it is financially feasible to use an alternate fuel in the facility.

1. *Comments*—(a) *Technical Capability.* A number of comments received by ERA noted that in proposing to find technical capability on the basis of an ERA determination of actual use of an alternate fuel or alternatively on the basis of design capability to burn such fuel, ERA was not, at least in the latter instance proposing to find the "real" technical capability called for under sections 301(b) and 302(a) of the Act.

ERA wishes to clarify the significance of design capability in the context of its application in the two-step process called for under the Act for the technical capability finding. The first step, required for issuance of a proposed prohibition order under sections 301(b)(1) or 302(a)(1) of the Act, calls for a finding that a facility "has" or "previously had" the technical capability to use an alternate fuel. ERA believes that design capability to burn alternate fuel establishes that a facility "previously had" technical capability to use that fuel and provides "reasonable evidence," under the terms of the Act and its conference report (p. 81), that a facility "has" (in the absence of evidence of major alterations to a facility) technical capability to use the fuel.

Design capability, however, does not provide the only basis for finding that a facility has or had technical capability. A facility actually burning an alternate fuel, not included in its design specifications, would be held to have present technical capability to use that fuel. The Conference Report (p. 81) explains that a proposed order need be supported only by a finding based upon a "paper search" for technical capability. ERA believes that a finding based upon either design capability or actual use satisfies this requirement. In addition units designed to use petroleum or natural gas may also, under certain circumstances, be considered able to use certain liquid or gaseous alternate fuels: for example, a unit designed to burn natural gas also "has" the technical capability to burn medium BTU gas from coal (assuming such gas is available). Furthermore, a unit designed to burn oil may, depending upon the chemical characteristics, be a unit that "has" the technical capability to burn liquefied coal. The fact that certain minor adjustments may be necessary does not render this a "hypothetical" as opposed to a "real" capability. Even an oil fired unit converting from the use of #2 distillate to #6 residual oil may be required to adjust or replace burner nozzles and add soot blowers. ERA views these alterations as minor adjustments the need for which does not render a unit incapable of burning a particular fuel.

Where ERA finds that a facility can burn an alternate fuel, based upon its design specifications, actual use, or on the other grounds, ERA will initially find that the facility "has" the requisite capability. Where a facility has been altered and lost the capability to burn an alternate fuel it was designed to burn, ERA will nonetheless find that the unit "previously had" the requisite capability.

A second step is required by sections 301(b)(2) or 302(a)(2) of the Act, for issuance of a final prohibition order. In order to issue a final order, ERA must make a finding, supported by substantial evidence, that "real" capability to use an alternate fuel exists. ERA must find either that a facility has the technical capability to use an alternate fuel (whether or not it was expressly designed to burn such fuel and whether or not it actually burned such fuel), or if it previously had such capability and lost it through alterations, it could have it again without substantial physical modification or substantial reduction in rated capacity. Any modifications to a unit altering the present ability of the unit to use an alternate fuel it was designed to burn, therefore, will be fully considered by ERA in evaluating whether the unit could have alternate fuel capability again without undergoing substantial modification or substantial derating.

ERA also received related comments noting that essential to ERA's finding of "real" capability to use an alternate fuel is the presence of pertinent fuel handling and storage systems and pollution control equipment. ERA believes that real technical capability of a facility to burn a particular alternate fuel is dependent upon the ability of the unit from the point of fuel intake to sustain combustion of that fuel and to maintain heat transfer. Typically, most potential prohibition order recipients would lack installed and operating alternate fuel storage and handling equipment, and control equipment necessary to burn an alternate fuel in compliance with applicable air pollution requirements. ERA believes that if the absence of such appurtenant facilities could suffice to prevent a finding of technical capability, the order-issuing provisions of sections 301(b) and 302(a) would be so restricted that the authorities conferred by Congress in those sections would be rendered to little or no effect. ERA will therefore make its technical capability finding on the basis of the characteristics of the unit under review, and will not normally consider the absence of fuel storage and handling or pollution control equipment as bearing upon the question of technical capability. The financial consequences of a need for such equipment will be taken into account in assessing the financial feasibility of a conversion to alternate fuels.

ERA received a number of comments suggesting that the technical capability finding should be limited to an assessment of the technical capability of a unit to burn coal but not other alternate fuels. Other comments were critical of ERA's proposal to consider, in certain cases, alternate fuels not included in the purchaser's design specifications for a facility. Adoption of these recommendations would not comport with the provisions of FUA which call for an affirmative finding of technical capability with respect to "coal or another alternate fuel." A unit may be fully capable of burning certain alternate fuels by virtue of its ability to burn either petroleum or natural gas. The fact that these alternate fuels may not have been available, or that their use was not foreseen at the time the purchaser's design specifications were prepared, does not alter the fact that the unit "has" the technical capability to burn selected alternate fuels, provided such alternate fuels are currently available. Congress intended "to the extent permitted by this Act, to encourage the use of synthetic gas derived from coal or other alternate fuels" (Section 102(b)(4)), and to "encourage and foster the greater use of coal and other alternate fuels" (Section 102(b)(3).)

With regard to the technical capability of a unit to use synthetic fuels, ERA received comments that FUA requires that facilities to convert coal or other fuel to synthetic fuel exists or did exist. ERA agrees that before such a technical capability funding regarding the use of synthetic fuels can be made the facility to convert coal or other fuel to a synthetic fuel must presently exist at the time of the proposed order, or have existed, although not, as some commenters asserted, at the same site as the unit in question.

Other related comments recommended that ERA should be limited in making the technical capability finding to alternate fuels which are available at a reasonable price. ERA believes that considerations of the reasonableness of fuel costs are properly a part of the financial feasibility finding (and the "substantially exceeds" cost exemption) and not of the finding of technical capability.

Several commenters suggested that ERA should consider, for its technical capability finding, only those alternate fuels which are suitable for use in the unit without detrimental effects. ERA will consider potential adverse effects on a facility which might result from use of an available alternate fuel as part of the technical capability finding for issuance of a final order. While these effects may bear upon the ability of a unit to sustain combustion of an alternate fuel, they will not necessarily foreclose a technical capability finding, since they may be able to be overcome with only minor adjustments not necessitating substantial physical modifications or subtantial derating.

One comment noted that ERA had erroneously omitted the word "and" at the end of § 506.2(a)(2). ERA has corrected this inadvertent omission.

(b) *Substantial Physical Modification.* ERA received a number of comments critical of its proposal to find that a facility does not require substantial physical modification if it has the requisite furnace configuration and tube spacing to burn an alternate fuel. Many comments suggested that ERA should consider the presence of coal, ash handling and storage facilities, and pollution control equipment.

ERA will assess the substantiality of physical modifications required to attain technical capability on a case-by-case basis. Acting on the assumption that Congress did not intend to create a significant overlap between "findings and exemptions," ERA distinguishes the requirements ERA must satisfy in making this finding from those incumbent upon the petitioner in presenting an exemption request. The scope of this assessment is derivative of the technical capability finding. ERA will weigh those modifications that involve the elements and characteristics, from the point of fuel intake, that are physically necessary to sustain combustion and maintain heat transfer (including adequate ash removal capability). Significant alterations affecting the furnace configuration or a complete respacing of the tube would likely be "substantial." A combination of modification involving changes required for bottom ash removal, related construction and engineering work, and other modifications to the boiler, other than furnace configuration or tube spacing, may, in some circumstances, cause modifications to be considered "substantial." While ERA will remain flexible in considering pertinent factors, pollution control equipment, such as precipitators or scrubbers, will not be weighed in assessing the substantiality of the modifications to the facility, nor will fuel handling equipment. The cost of such equipment will be taken into account both in determining whether to make a finding of financial feasibility and in the cost exemptions (see. §§ 504.21, 504.31, 506.21, and 506.31).

(c) *Substantial Derating.* Many comments criticized ERA's proposal that a derating of less than 25 percent of a unit's design capability would not be considered "substantial." Some commenters specifically suggested modification to a 10 percent ceiling; ERA has revised its proposal so that a derating of less than 10 percent would not be considered "substantial." Deratings equal to or in excess of 10 percent will be evaluated for their substantiality in the context of site-specific circumstances. Typically, units that are the subject of a prohibition order will not have installed any operating air pollution control equipment sufficient to burn coal in compliance with applicable environmental equipments. The installation and use of air pollution control equipment alone, can, in many cases, produce a derating of close to 10 percent. Moreover, the shift to coal itself will, because of differences in energy density and fuel flow characteristics, typically involve some derating. Thus if a derating of less than 10 percent should constitute a "substantial" derating, the authority conferred by Congress to prohibit by order could be almost entirely nugatory.

Other comments criticized ERA's proposal not to include deratings resulting from the addition of pollution control equipment. ERA has adopted a case-by-case approach for evaluation of the substantiality of deratings equal to or in excess of 10 percent. Derating due to pollution control equipment enters into the assessment of substantiality, as does derating resulting from any other reason. If the only derating is due to air pollution equipment, however, and amounts to less than 10 percent, ERA will not consider the derating to be substantial.

In assessing whether unit deratings of 10 percent or more are "substantial," ERA will consider the impact of the reduction in available capacity on the site (or, in the case of utilities, on the system) at which the facility is located, as well as on the unit itself. For example, ERA may find that the derating of a unit far in excess of 10 percent is not "substantial" if it produces no appreciable effect upon the operation of a facility with considerable excess capacity.

(d) *Financial Feasibility.* In the proposed rules applicable to the financial feasibility of alternate fuel use by an existing powerplant or MFBI, ERA proposed a test which considered alternate fuel use to be financially feasible if the cost of using an alternate fuel did not substantially exceed the cost of using imported petroleum, and if the firm had the ability to raise the capital necessary to convert the unit.

Many of the commenters argued that incorporation of the substantially exceeds test was contrary to the intent of the Act, asserting that the financial feasibility test was a measure of impact on the facility or the utility system, not of when excess costs are "substantial" in light of the purposes of the Act. The commenter argued that financial feasibility must be determined on a case-by-case basis in order to take into account a variety of factors applicable to each particular facility and corporation. They stated that a formula test and an examination of the ability of a firm to pay for the conversion of the unit were too inflexible for ERA to make a proper evaluation.

The commenters asserted that ERA must take into consideration any relevant factor applicable to the ability of the facility to compete in the marketplace, the effect on the business done by the facility at the site where it is located, the effect on the parent corporation, if any, and any unreasonable shutdown at the facility during the period required for the conversion. The commenters further argued, in the case of a powerplant, that ERA should consider the impact of the required conversion as part of the total impact of the Act and other regulatory demands on the entire utility system, including additional costs which may be imposed upon the system as a result of the prohibitions applicable to both new and existing facilities under the Act.

The commenters also stated that in assessing financial feasibility, it is essential to take into account costs (for example, for pollution control equipment) which, the commenters contended, were excluded in the proposed rule from the test for the cost exemption.

To address the last group of comments first, we note that the cost test adopted in the interim rule takes into account all cash outlays for capital investment (including pollution control equipment), and forward values outlays occurring before the commencement of operations at the facility. These objections are therefore met by the interim rule.

The issues concerning the nature of the financial feasibility test are not so readily resolved.

No doubt some of the factors cited by the commenters may be relevant in particular cases to a determination of financial feasibility. However, it cannot be assumed that factors of the kind cited by the commenters will be relevant in all or even most cases. ERA believes that in many instances financial feasibility can and should be determined only on a formula approach, and that to leave this determination solely to a case-by-case method would involve unnecessary complexity.

ERA believes it appropriate to use a formula and the availability of capital as a presumptive measure of financial feasibility unless other factors can be shown to be relevant. By using a formula in this way, the scope of the inquiry should be narrowed in most cases. Because the formula is a presumption, a firm will have the opportunity to present other evidence that even though under the formula conversion appears to be financially feasible, other relevant factors, e.g., the competitive viability of the enterprise supported by the unit, make the required conversion inappropriate. ERA will have the ultimate burden of persuasion on the question of financial feasibility.

A formula that compares the costs of conversion with the costs of burning imported petroleum provides a reasonable presumptive measure of the financial feasibility of conversion. The provisions of the cost exemption enable such comparison, and ERA is adopting them for the interim rule on financial feasibility. Moreover, ERA believes it reasonable to assume, pending experience under the Act, that for many firms, it will be financially feasible to convert to an alternate fuel at a cost up to the 1.3 ceiling which the substantially exceeds index sets. Accordingly, ERA will presume that a conversion is financially feasible if the cost of converting equates to an index of 1.3 or less.

ERA has modified the cost formula to be used as the presumptive measure of financial feasibility in order to account for a firm specific factor. In calculating the cost of using an alternate fuel as compared to the cost of using imported petroleum, ERA will use your firm's own cost of capital rather than a national average. We are doing so because the perspective of the financial feasibility test is more that of the firm than the cost exemption. The firm's own cost of capital therefore seems more appropriate for the presumptive test even though the firm may, in any event, put in issue additional factors specific to its situation. ERA may take into account other relevant factors which you demonstrate to be relevant to a determination of financial feasibility for a particular facility or firm. Thus, in the case of a powerplant, ERA will allow you to demonstrate the impact of the Act on your entire utility system. In considering the effect of the conversion on an MFBI, ERA will allow you to demonstrate the effect of the conversion on the competitive viability of the facility.

ERA believes, in general, that most public utilities can raise the capital necessary to convert a powerplant to alternate fuel use, especially in light of the ability of a utility to achieve rate relief through action by the appropriate regulatory authority. In the case of MFBI's, ERA believes that the determination of capital availability should be dependent upon the firm's ability to raise capital and not just the ability of the enterprise directly supported by the individual unit in question.

Some commenters asserted that ERA should not use the cost of imported petroleum in determining whether or not it is financially feasible to convert to alternate fuel as this accounting creates a higher fuel price for oil than most existing facilities are actually paying due to domestic price controls. ERA believes that, as a matter of policy under FUA, whenever there is occasion to make a cost comparison between alternate fuels and petroleum, the comparison should be to the true replacement cost of petroleum. Since the marginal source of supply is imported petroleum, a comparison with replacement cost is a comparison to the cost of imported petroleum. ERA recognizes that the considerations that lead to a cost-comparison formula as a presumptive measure of financial feasibility may not compel the choice of an index that is identical to the substantially exceeds index. ERA invites comments on whether, in addition to the shift to the firm's own cost of capital, the substantially exceeds test should be further modified when it is used as the presumptive measure of financial feasibility. Commenters may also wish to address, for example, whether another type of index or formula should be used as a presumptive measure of financial feasibility.

C. Prohibition Against Excessive Use in Mixtures (§§ 504.5(d) and 506.2(d))

Sections 301(c) and 302(b) of FUA give ERA the discretionary authority to prohibit the use of petroleum or natural gas, or both, in amounts in excess of the minimum amount necessary to maintain reliability of operation consistent with reasonable fuel efficiency in units in which use as a primary energy source of a mixture of petroleum or natural gas and alternate fuel is technically and financially feasible.

For purposes of exercising this discretionary authority, ERA will use the case-by-case standards for technical feasibility and the standards for financial feasibility that are found in §§ 504.5 and 506.2. In determining whether a mixture is financially feasible, ERA will take into consideration the cost of any modification necessary to burn a mixture of petroleum or natural gas and an alternate fuel.

Prohibitions against the use of natural gas or petroleum in amounts necessary to maintain reliability of operation consistent with reasonable fuel efficiency shall only be imposed by order to specific existing facilities. If either a proposed order or a final order for a mixture is issued, the facility will be provided opportunity to demonstrate qualifications for, or petition for in the case of final orders, any of the exemptions set out under Parts 504 and 506 except for the permanent exemption applicable to mixtures.

D. Cost Calculations (§§ 504.12 and 506.12)

Sections 311 and 312 of the Act provide that ERA must grant an exemption from the prohibitions of the Act when alternate fuel supplies are available only at a cost which substantially exceeds the cost of using imported petroleum. After evaluation of the comments received during the public comment period, ERA is now adopting interim rules which provide the criteria, methodology and evidentiary requirements to be used by a petitioner in petitioning for an exemption based upon the cost of converting and operating a facility which burns an alternate fuel. In all cases, we have determined that the appropriate cost comparison must take into consideration the additional captial, operation, maintenance and fuel costs associated with specific fuel choices in existing facilities, and they must be expressed in real terms discounted to present value. Specific aspects of the cost calculation were addressed in the preamble dealing with the cost test for new facility regulations (44 FR 28957–61, May 17, 1979).

In addition to the methodology adopted in this interim rule ERA is soliciting comments on two alternative methodologies for computing cost which are discussed in greater detail in Part III of this Preamble.

For purposes of this interim rule ERA is adopting a definition of "substantially exceeds" as 1.3 times the cost of using imported oil. The justification for this value is provided in the preamble dealing with new facility regulations (44 FR 28953–57 and 29018–9, May 17, 1979). ERA will revise the index from time to time after public notice and an opportunity to comment. Revisions in the index shall become effective for all ERA decisions after final publication; however, the relevant index for a specific petition will be the index in effect at the time the petition is submitted, or the index in effect at the time a decision is rendered, whichever is lower.

ERA is inviting comment on the appropriateness of this cost test, the two other alternative cost tests discussed in Section III of this preamble, and other possible approaches or changes to such tests. In particular we invite comment on certain parameters used in the various cost test approaches including the appropriate treatment of remaining useful life, discount rates, capacity utilization and fuel prices.

In addition to comments addressed in the above cited sections of the preamble to the interim rules applicable to new facilities, several commenters expressed concern that the cost test did not account for the impact of derating a unit when the unit is converted from oil or gas to alternate fuel. We have modified the cost calculation to include the impact of derating upon cost. The impact of derating will be assessed differently for MFBI's and powerplants.

For MFBI's, we will assume that your MFBI will generate on an annual basis the same amount of steam or energy after the conversion to alternate fuel as it generated while operating on oil or natural gas. ERA will base this computation on the 5-year average annual usage of the unit as described in § 506.12(d) of these regulations.

You may come forward with evidence that the 5-year average does not adequately account for your needs because historical, daily or seasonal peaking requirements exceed the capacity after derating. If you choose in this way to put in issue the adequacy of the 5-year average, you should also address the least cost alternative means of replacement of this needed capacity.

The choice of the least cost alternative for the additional capacity must reflect additional costs associated with increased firing of the unit to be converted, the use of other units at your site, purchased energy or the purchase of new capacity. If your claim additional capacity is needed, you must adjust the capital outlay for the "make-up" unit by the remaining useful life of the make-up unit according to the procedures identified in § 506.12 of these regulations.

If the size of the needed make-up capacity is less than the size of the exclusion from aggregation in § 500.2 of these regulations, and the least cost alternative is an oil- or gas-fired facility, the costs of such a make-up facility will be the costs considered in the cost formula.

It may be, however, that the size of the needed make-up capacity is greater than the size of the exclusion from aggregation in § 500.2 and the least cost alternative is an oil- or gas-fired facility. In such a case, you should raise the issue of how to account for the make-up capacity in a pre-petition conference. Where the least cost alternative is oil- or gas-fired, and where it appears that such a facility would be likely to receive an exemption from the prohibitions of Title II of the Act, the costs of that alternative will be included in the cost test as the costs of make-up capacity.

For powerplants, we will assess costs attributable to derating on the assumption that your powerplant will generate the same number of kilowatt hours on an annual basis before and after conversion. ERA will base this assessment on the 5-year average annual usage of the unit as described in § 504.12(d) of these regulations.

If you believe this approach does not adequately account for the effects of lost capacity, you may rebut these findings based upon the impact of derating upon your electric region. Since powerplants usually operate in an interconnected manner, any treatment of derating other than the one stated in the previous paragraph must be on the basis of economic dispatch of powerplants in your electric region. Section 504.12 of these interim regulations permits the powerplant to compute cost on the basis of economic dispatch of all units in your electric region, which approach can account for the impact of derating.

If you can demonstrate that additional capacity is required to account for the effects of derating, you must identify the least cost alternative (as specified in § 504.12, similar to that specified for MFBI's above).

In Section III below, additional comments are invited on issues relating to the cost test for both new and existing facilities.

E. No Alternative Power Supply—General Requirement for Permanent Exemptions (§ 504.13)

Section 312 of the Act provides for a permanent exemption due to State or local requirements and for intermediate load powerplants. To qualify for either of these exemptions, a petitioner must demonstrate that despite diligent good faith efforts, there is no alternative supply of electric power available within a reasonable distance at a reasonable cost without impairing short- or long-run reliability of service which the petitioner could obtain.

Several commenters objected to the proposed requirements concerning the construction of new alternate fuel-fired plants as a means of demonstrating that there is no alternative supply of power. The commenters contend that section 313(b) of the Act only requires a consideration of purchasing power from other sources.

Some comments suggested that purchased electricity should appropriately be considered as an alternate source of power only when it is available under long-term firm supply contracts. Other comments were to the effect that purchasing power for an extended period of time was not a reasonable requirement since excess capacity is rarely available in an electrical supply region over a long period.

Comments were received pointing out that the proposed rules failed to provide for consultation with the Federal Energy Regulatory Commission, as required by section 313(b)(2), of the Act, before making a finding with respect to an alternative power supply.

ERA received several comments recommending that the term "reasonable distance," as used in § 504.13 of this interim rule, should be treated as a factor independent of cost considerations. Defining unreasonable distance in cost terms, it is argued, is not what Congress intended, and the reasonable distance concept should be explicitly defined as including either the State or some region less than the electrical region.

ERA received these and similar comments relating to this general requirement for exemptions for new facilities. For a discussion of such comments, see "General Requirement—No Alternative Power Supply," published May 17, 1979, at 44 FR 28959. ERA's resolution of the issues raised by these comments is the same for existing facilities as for new facilities.

The rule, however, for existing facilities does differ slightly from the rule for new facilities.

For new facilities, petitioners are required to examine the availability of purchased power during the first year of scheduled operations of proposed oil- or gas-fired units. Petitioners for a permanent exemption for existing facilities due to State or local requirements or for an intermediate-load powerplant, will be required to demonstrate that there is no alternate supply of power available in three different situations. First, the requirement applies, in the case where a proposed prohibition order has been issued by ERA, only for the first year after the date on which the order could reasonably be expected to become effective. Second, the requirement will apply, in the case where a petitioner proposed to use natural gas in excess of a statutory prohibition, only for the first year in which the excess natural gas is proposed to be used. Third, the no alternate power showing applies, in the case in which a final prohibition order has been issued by ERA, only for the first year in which it is proposed that the facility subject to the order would use petroleum or natural gas.

F. Use of Mixtures—General Requirement for Permanent Exemptions (§§ 504.15 and 506.14)

The proposed rule would have required petitioners for a State or local exemption under section 312(b) of the act to consider the use of a mixture(s) for which a fuel mixtures exemption under §§ 504.36 and 506.36 of these regulations would be available. The comments point out that section 313(a) of the Act expressly excepts an exemption for State or local requirements from the general requirement on the use of mixtures. ERA agrees with the comment and has deleted the subject requirement from these regulations.

G. Use of Innovative Technologies (§§ 504.25 and 506.25)

Section 311(c) of the Act provides for a temporary exemption based upon the use of innovative technologies. The proposed rules contained a requirement that the petitioner demonstrate that the powerplant or installation could not comply with the applicable prohibitions by using an alternate fuel before the end of the proposed exemption period. Several commenters objected to this requirement as imposing a burden which was not in consonance with the legislative purpose in providing the exemption. ERA agrees with the commenters and has deleted the requirement relating to alternate fuel use from the rule as adopted.

Other commenters objected to a requirement that petitioners must present evidence of contractual commitments to use an innovative technology for use of an alternate fuel before a petition for an exemption is approved. The objection was based on the ground that a petitioner is required to accept an unfair burden in the form of a risk that the petition will be denied, thereby subjecting the petitioner to significant financial penalties for nonperformance of the contract. ERA believes that petitioners for this exemption can and will take prudent steps to enter into contractual commitments for the use of innovative technologies which are conditioned upon the grant of an exemption. Therefore, ERA has decided not to change the proposed regulation. Nevertheless, ERA encourages petitioners for this exemption to raise their plans to use an innovative technology with ERA at the earliest practicable time, for example at either a pre-proposed order conference or a pre-petition conference.

H. Retirement (§§ 504.27 and 506.26)

Section 311(d) of the Act provides for a temporary exemption for units to be retired. The proposed rules required the petitioner to demonstrate, as a condition of eligibility for the exemption, that the unit is not capable of complying with the applicable prohibitions contained in Title III, Subtitle A of FUA by consuming coal or other alternate fuels before retirement of the unit. A number of comments were received which indicated that the proposed criteria for eligibility were inappropriate for the retirement exemption. ERA agrees with these comments and has deleted the proposed required showing.

Comments were received which urged ERA to adopt the view that a retirement exemption under § 504.27 should be available to powerplants which had previously been placed on cold standby status. Such powerplants may be the subject of a petition for exemption for retirement under § 504.27. The petitioner must, however, commit the unit to "permanently cease operation" upon termination of the exemption period; thus, the unit may not continue in a cold standby status after termination of the exemption.

Some commenters suggested that § 504.27 of the proposed rule could be construed to require that powerplants for which this exemption was sought could not be retired earlier than originally planned. ERA does not so construe these regulatory provisions. A utility always retains the option of retiring a unit in advance of the planned retirement schedule submitted in support of the petition for exemption.

One comment suggested that section 311(d) retirement exemptions could be extended beyond five years, until December 31, 1994. ERA disagrees and notes that the phrase "may not extend beyond December 31, 1994" contained in section 311(h)(3) of the Act does not provide authority to grant an extension beyond the 5-year limit contained in paragraph (1) of section 311(h), but rather it further delimits the maximum 5-year duration period for a temporary exemption in those instances where the retirement exemption period commences after January 1, 1990.

I. Peakload Exemptions (§ 504.29 and § 504.38)

Several commenters asked for a clarification of the 12-month period which will be used for calculating maximum allowable generation of a peakload powerplant. ERA has set the applicable period as the 12-month period beginning with the first day of the month following the granting of the exemption.

One commenter objected to the exclusive use of "loss of load probability" (LOLP) technique as inappropriate to the determination of whether an exemption denial would "likely" result in impairment of reliability of service. ERA has expanded the test so that LOLP is but one factor to be considered, and the applicant may submit additional bases for an exemption.

One commenter expressed the opinion that FUA does not authorize the use of the same test for determining whether the cost of using an alternate fuel "substantially exceeds" the cost of using imported petroleum and for determining whether compliance with the prohibitions of the Act would be an "unreasonable expense" for a peakload powerplant. ERA has modified this provision to asses reasonableness on a case-by-case basis.

One commenter stated that ERA was required to use the definition of utility peakload volumes appearing in section 501(f) of FUA. ERA had decided not to use that definition since it is expressly applicable only to subsection (b)(4)(B) of section 501 regarding the electric utility system compliance option. ERA believes, as a matter of policy that the definition specifically developed for this exemption is more reasonable.

Other commenters objected that the test applied to determine "likelihood" of impairment of reliability for purposes of the peakload exemption should be less stringent than the test for the reliability exemption which speaks in terms of "necessary" to prevent impairment. ERA believes that in setting the tests for the two exemptions at the same level, it has significantly scaled down the requirements of the reliability exemption. It does not believe it has imposed an additional burden upon applicants for the peakload exemption.

One commenter requested a clarification that in determining whether a unit is a peakload unit, ERA not look to past history. ERA has made clear that the period to be analyzed in computing LOLP is the 12-month period beginning on the first day of the month following the effective date of the exemption.

One commenter stated that the requirement of a compliance plan is inappropriate for the temporary exemption for peakload powerplants. ERA, while recognizing that FUA does not require a compliance plan in the case of a temporary peakload exemption, believes that section 314 of the Act gives it the authority to require one concomitant to its authority to impose terms and conditions on exemptions.

J. Use of natural gas by powerplant with capacity of less than 250 million BTUs per hour (§ 504.40)

Section 312(h) of the Act provides for a permanent exemption for the use of natural gas by existing powerplants which have a design capability of consuming fuel (or any mixture thereof) at a fuel heat input rate of less that 250 million BTUs per hour, which were used as baseload powerplants on April 20, 1977, and which are not capable of consuming coal without substantial modification or substantial derating of the unit. The Act further provides that the exemption authorized under section 312(h) may only apply to the prohibitions under section 301 of the Act and prohibitions established by final rules or orders issued before January 1, 1990.

ERA has received several comments objecting to certain of the requirements contained in the proposed rules. Commenters objected to the proposal that petitions under section 312(h) be filed on or before December 31, 1988. ERA recognizes that there may be instances where a petition could be properly filed after December 31, 1988, and has deleted the proposed restriction.

Other commenters objected, in view of the statutory reference to a single date, April 20, 1977, with respect to the baseload use determination, to the requirement for a detailed history of the fuel consumption of the powerplant for 1976 and 1977 on a monthly basis for each fuel consumed and the demonstration of kilowatt hours of electrical generation for 1976 and 1977. ERA believes that it is unrealistic, and in certain cases would be unfair (for example where special circumstances may have caused the powerplant to be operating as an intermediate load or peakload powerplant or even out of service on April 20, 1977) to make a determination as to which units were baseload powerplants by reference to any single date. FUA defines the term "base load powerplant" as a powerplant the electrical generation of which in kilowatt hours exceeds, for any 12-month calendar-month period, such powerplants design capacity multiplied by 3,500 hours. In view of the comments received, ERA has revised the requirements for information as to electrical generation and fuel consumption to cover the calendar year 1977.

A number of comments objected to the use of a cost calculation formula with reference to the finding on substantial physical modification and the proposed 25% test for the finding on derating. ERA has deleted the cost calculation formula and further revised the basis for both findings, as set out in §§ 504.5 and 506.2 relating to the findings ERA must make in issuing individual prohibition orders. A discussion of the reasons for these revisions is contained in the section of this preamble entitled "Authority to Prohibit Where Alternate Fuel Capacity Exists."

K. Use of liquefied natural gas (§ 504.41)

Section 312(i) of the Act provides for a permanent exemption for the use of liquefied natural gas (LNG) by certain powerplants. To qualify for the exemption, a petitioner must obtain a certification from the Administrator of the Environmental Protection Agency (or the appropriate State air pollution control agency) that the use of coal by such powerplant as a primary energy source would cause or contribute to a concentration of pollutants for which ambient standards are being exceeded and would result in a violation of certain environmental standards. The proposed rules require that the certification be made for coal or any available coal derived fuel. Comments were received objecting to the inclusion of alternate fuels other than coal. Section 103(a)(5) of the Act defines the term "coal" to mean "anthracite and bituminous coal, lignite, and any fuel derivative thereof." Therefore, ERA has not changed the requirement in adopting these rules.

Comments were also received objecting to a proposed criterion of eligibility for the exemption that the LNG to be used at the petitioner's powerplant be produced in a foreign country. The comments suggested that this proposal exceeded the requirements of the Act and placed an unnecessary burden on the petitioner. ERA disagrees with the comments. ERA believes that the language contained in section 312(i) of the Act relating to LNG must, as a matter of statutory construction, have a meaning independent of "natural gas" since FUA is premised on the need to preserve natural gas because supplies in the Unted States are not ample.

An interpretation of section 312(i) which would permit a use of natural gas that is otherwise prohibited by the Act merely because the gas had first been converted to a liquid form would clearly frustrate the purposes of the statute. Such an interpretation would construe section 312(i) as an exemption to use natural gas by another name. In order to give section 312(i) an independent meaning within the overall structure of the Act, ERA believes that it is necessary to grant the exemption to use LNG only where such fuel is a net addition to domestic supplies of natural gas. Therefore, ERA is adopting a rule that the LNG to be used at the petitioner's powerplant be produced outside of the continental United States.

Commenters also objected to ERA's proposal that from time to time the exemptions would be reviewed and terminated when ERA finds that there is an available supply of synthetic fuel suitable for use by the exempt powerplant. ERA had deleted this provision from the rule as adopted, but will consider on a case-by-case basis the inclusion of such a provision as a term and condition of any order granting this exemption.

III. Specific Comments Requested

A. Alternative Cost Calculation for Substantially Exceeds (§ 503.5, § 504.12, § 505.5, § 506.12)

Sections 503.5 and 505.5 of the Interim Regulations for New Facilities Exemptions, published in the Federal Register on May 17, 1979, and §§ 504.12 and 506.12 of these Interim Regulations for Existing Facilities provide explicit procedures for determining whether the cost of using alternate fuel substantially exceeds the cost of using imported oil. These calculation procedures specify the computation of the cost of fuel as the cost of capital, operations and maintenance and delivered fuel discounted to the present.

ERA invites comments on the cost calculation procedure adopted for the Interim Rule and two variants, discussed below. In particular, the comments should address the comparative merits, if any, of the cost calculation procedures as adopted in the Interim Rule and specified in the variants as applied to new and existing facilities.

(1) *Cost Calculation Procedure Adopted in the Interim Rule.* The cost calculation procedures adopted for the Interim Rules in §§ 503.5, 504.12, 505.5, and 506.12 require computation of a ratio of the cost of using alternate fuel to the cost of using imported oil. If this ratio exceeds a specified index, the cost of using alternate fuel substantially exceeds the cost of using imported oil. The costs of using alternate fuel and imported oil are based upon the petitioners' current price of alternate fuel and oil (the latter is subsequently adjusted to reflect imported oil price). For the purposes of these cost calculations, these fuel prices are the same, in real (uninflated) dollars, for the life of the facility. Our judgment as to the change in future prices is embedded in the "substantially exceeds index" itself.

For these Interim Rules, ERA has set this "substantially exceeds index" at 1.3. As discussed in the preamble to the Interim Rule published on May 17, 1979 (44 FR 28953 and 29603), ERA set this index at 1.3 based upon our judgment as to the social benefits associated with increased alternate fuel use and future increases in the gap between oil and coal prices.

(2) *Variant #1—Ratio with Explicit Trajectory.* Under this varaint, computation of a ratio of the cost of using alternate fuel to the cost of using imported oil would be required as in the Interim Rules. However, ERA would specify an explicit price difference trajectory—the annual percentage rate at which the gap between imported oil and coal prices would increase. The applicant would then adjust the annual cost of imported oil to appropriately reflect the specified increase in the imported oil/coal price gap. The substantially exceeds index would then be restricted to reflect our judgment of the social benefits associated with increased alternate fuel use.

(3) *Variant #2—Net Present Value with Explicit Trajectory.* Under this variant, rather than computing a ratio of the cost, as in the Interim Rule, the applicant would compute the difference in the cost of using alternate fuel and the cost of using oil. An exemption would be allowed when the cost of using alternate fuel is greater than the cost of using oil; the imported oil price would be adjusted by a specified dollar increment to reflect our judgment of the social benefit of increased alternate fuel use. In addition, as in variant #1, the oil price would reflect imported oil price adjusted on an annual basis for specified increase in the imported oil/coal price gap. The cost of using alternate fuel and oil would be computed as adopted in the Interim Rule, except for the specified increases in the oil price.

B. Terms and Conditions (§§ 503.12, 504.17, 505.9, 506.16).

Sections 214 and 314 of FUA provide the authority to impose terms and conditions upon granting an exemption. ERA has in the past required, as a condition of exemptions granted to new facilities permitting the use of oil or gas, that such facilities be constructed with the capability to use specified liquid and/or gaseous alternate fuels. ERA is considering adopting this requirement as a generic condition for all exemptions granted. ERA is also considering specifying the petroleum or natural gas fuel that the facility would be permitted to use and requiring that a new facility have the capability to burn a wide variety of petroleum and gaseous fuels.

We solicit comments on these proposals.

IV. Amendments.

ERA is making several amendments to its previously issued Interim Rules in order to provide for a more complete implementation of FUA and to correct certain oversights made in the previous rules. Each change is discussed below in the order in which it appears in the regulations.

A. Definition of "Combined cycle unit" (§ 500.2(a))

ERA is substituting the term "boiler" for "steam turbine units" to more accurately reflect the technical make-up of a combined cycle unit.

B. Definition of "major fuel-burning installation" (§ 500.2(a))

Excluded from the definition of major fuel-burning installation are pumps or compressors used for certain purposes provided a certification of such use has been submitted to ERA. ERA has amended the definition to clarify when such a certification is required and the information necessary to satisfy this requirement.

C. Definition of "Primary energy source" (§ 500.2(a))

In the May 15, 1979, Federal Register (44 FR 28532), ERA discussed the exclusion from consideration as a primary energy source the amount of fuel used for the purposes enumerated in section 103(a)(15)(A) of the Act equal in total to five percent of the total energy in Btu's consumed per year by the particular unit. However, in § 500.2(a) under the definition of primary energy source, ERA excluded up to five percent of the unit's current year Btu *output*. ERA is now amending the regulation by deleting the term "output" and inserting in its place "input," thereby resolving the inconsistency between the preamble discussion and the regulation.

D. Aggregation of Existing Facilities (§ 500.2 (c) and (d))

In the May 15, 1979, Federal Register (44 FR 28530, 28542–28543), we reserved §§ 500.2 (c)(3) and (d)(3) for the criteria we would employ in aggregating existing facilities at a single site in order to determine if they constitute a powerplant or an MFBI, subject to the provisions of Title III of FUA. We are now adopting regulations setting forth such criteria in this Interim Rule.

We previously adopted, in §§ 500.2 (c)(1) and (d)(1), the criteria to be used for aggregating a combination of new and existing units at a single site; and, in §§ 500.2 (c)(2) and (d)(2), the criteria for aggregating a combination of two or more new units at a single site. As explained in greater detail in those sections, ERA will aggregate toward the 250 million Btu's per hour threshold, in the case of a combination of new and existing units at a site, only those existing units with a heat input rate equal to or greater than 100 million Btu's per hour; and, in the case of a combination of new units at a site, only those units with a heat input rate equal to or greater than 50 million Btu's per hour. Where either of the foregoing combinations of units attains or exceeds the 250 million Btu's per hour heat input threshold at a single site, ERA will consider each of the constituent facilities to be an MFBI or powerplant, subject to applicable prohibitions of the Act.

For purposes of coverage under Title III of FUA, if you have two or more existing units in combination at a single site, ERA will aggregate toward the 250 million Btu's per hour threshold any such units having a heat input rate equal to or greater than 50 million Btu's per hour. When aggregated in accordance with this criterion, ERA will consider all units contributing to attainment of and/or surpassing the 250 million Btu's per hour threshold, to be either existing powerplants or existing MFBI's subject to the prohibitions of Title III of the Act.

ERA's application by order or rule of the Title III prohibitions authorized by sections 301 (b) and (c) and 302 of the Act, is discretionary. ERA does not believe it would be appropriate to categorically exclude from aggregation existing units with heat input rates between 50–100 million Btu's per hour since the foregoing discretionary prohibitions under Title III are predicated upon ERA findings of technical capability (or, in the case of mixtures, technical feasibility) and financial feasibility to burn an alternate fuel. While such units may, in combination, be MFBI's or powerplants, you will not be prohibited under these sections from using petroleum or natural gas in the units if ERA, because of the characteristics of your existing facility, cannot meet its statutory burden of proving these findings.

ERA therefore believes that the 50 million Btu's per hour heat input floor for the aggregation of existing facilities at a single site provides a reasonable accommodation which will carry out the purposes of the Act to reduce the consumption of petroleum and natural gas, while avoiding any severe economic impacts caused by the conversion of small facilities.

The above represent ERA's present regulatory criteria governing the aggregation of units for purposes of determining their coverage under the Act. We may, in the future, lower any of the aggregation floors. For existing facilities, such a reduction might result from the development and refinement of technology for the conversion of smaller petroleum and natural gas-fired facilities to the use of alternate fuels as a primary energy source. ERA solicits your comments, on a continuing basis, on the feasibility and economics of such developing technologies.

E. Requests for a Public Hearing (§ 501.33)

ERA hereby amends section 502.33 of the interim regulations issued May 8, 1979, 44 FR 28530, in order to extend the period of time within which a petitioner for an exemption, a proposed prohibition order recipient, or any interested person, may file a request for a public hearing from 21 days to 45 days.

In the case of a petition for an exemption from a prohibition imposed either by the Act or by a final rule or order issued by ERA to an existing facility under Title III of FUA, this 45-day period commences when notice of the filing of a petition is published in the Federal Register in accordance with § 501.64. In the case of a proposed prohibition order, the 45-day period in which to request a public hearing commences upon the publication of the notice of availability of the Tentative Staff Report.

F. Procedures for the Issuance of Prohibition Orders to Existing Facilities (§§ 501.51 and 501.52)

ERA is amending subpart E of Part 501 by adding §§ 501.51 and 501.52 to provide a description of the procedures ERA will employ to issue prohibition orders to existing powerplants and installations. These procedures are discussed in great detail in Part II of this preamble.

G. Cost Calculation for Powerplants (§ 503.5)

Section 503.5(4)(i)(B) provides procedures for computing the cost of using alternate fuel and cost of using imported oil based on the operations of all powerplants in your electric region. We have amended this section to state, that in the event the cost of using imported oil (according to the procedures specified in these regulations) is negative or zero, the determination of substantially exceeds will be made on a case-by-case basis.

H. Site limitations exemption (§§ 503.22 and 503.33)

In order to correct an oversight and to provide consistency in the treatment of exemptions to powerplants and installations on the basis of site limitations, ERA is amending both the temporary and permanent exemptions for powerplants to state that the lack of adequate land is one of the limitations which could establish eligibility for a site limitation exemption.

V. Clarifications.

In the May 15, 1979, Federal Register, ERA discussed the treatment of internal combustion engines used for the generation of electricity (44 FR 28532). In the discussion, ERA stated that an internal combustion engine used for the generation of electricity is neither an MFBI nor an electric powerplant. It must be emphasized, however, that this exclusion from FUA coverage pertains only to internal combustion engines used for the generation of electricity for *sale or exchange.*

Both the interim regulations issued on May 8, 1979 (44 FR 28950, May 17, 1979) and the regulations issued herewith provide for an exemption based upon certain site limitations (§§ 503.22, 503.33, 504.22, 504.32, 505.12, 505.23, 506.22 and 506.32). Under the provisions of these regulations a siting problem relating to the installation or operation of pollution control devices would certainly be considered a qualifying site limitation. Furthermore, under §§ 504.25 and 506.25 (Innovative Technology exemptions) the development of innovative pollution control devices or techniques would qualify a petitioner for the exemption.

VI. Procedural Matters.

A regulatory analysis of this Interim Rule, as contemplated by Executive Order No. 12044, is contained within the draft regulatory analysis of the regulations regarding new facilities proposed on November 9, 1978, 43 FR 53974. A Final Environmental Impact Statement (FEIS) has been prepared pursuant to the National Environmental Policy Act (NEPA). Both the draft regulatory analysis and the FEIS may be obtained from ERA, 2000 M Street, NW., Room B-110, Washington, D.C. 20461, (202) 634-2170.

These revised rules have been submitted to the Office of Management and Budget (OMB) for clearance under the provisions of the Federal Reports Act. Any compliance with the data collection provisions of these Interim Rules may require revisions or additions as a result of OMB's action.

(Department of Energy Organization Act, Pub. L. 95-91, 91 Stat. 565 (42 U.S.C. 7101 et seq.); Powerplant and Industrial Fuel Use Act of 1978, Pub. L. 95-620, 92 Stat. 3289 (42 U.S.C. 8301 et seq.); E.O. 12009, 42 FR 46267)

In consideration of the foregoing, Parts 500, 501 and 503, Subchapter E, "Alternate Fuels" of Chapter II, Title 10 of the Code of Federal Regulations are amended, and Parts 504 and 506 of Subchapter E, as proposed on January 29, 1979, are hereby revised and adopted effective August 20, 1979.

Issued in Washington, D.C., July 11, 1979.
David J. Bardin,
Administrator, Economic Regulatory Administration.

PART 500—POLICY AND DEFINITIONS

1. Section 500.2 (a) is amended by the definition of "combined cycle unit" to read as follows:

§ 500.2 Definitions. [Amended]

(a) *General definitions.*

* * * * *

"Combined cycle unit" means an electric power generating unit that consists of a combination of one or more combustion turbine units and one or more boilers with a substantial portion of the required energy input of the boiler(s) provided by the exhaust gas from the combustion turbine unit(s). Use of small amounts of supplemental firing for the boiler does not preclude the unit from being a combined cycle unit.

* * * * *

2. In § 500.2(a), the definition of "major fuel burning installation" is revised to read as follows:

"Major fuel burning installation," "installation," and "MFBI" do not include—

(1) * * *

(2) * * *

Such certification must be made for all units with a design energy input rate of 50 million Btu's per hour or greater and which consume petroleum or natural gas. The following information is required:

(i) Unit size in Btu input;

(ii) Equipment function; and

(iii) Unit location, including all information which geographically locates the unit.

3. In § 500.2(a), the definition of "primary energy source," is amended by deleting in subparagraph (1) the word "output" and inserting in its place the word "input."

4. Section 500.2(c) is amended by adding a subparagraph (3) to read as follows:

(c) *Criteria for determining if your electric generating unit is to be aggregated and is a powerplant.* * * *

(3) *Existing Units.* If you have two or more existing electric generating units on a single site, ERA will aggregate towards the 250 million BTUs per hour threshold any existing unit with a heat input rate equal to or greater than 50 million BTUs per hour.

* * * * *

5. Section 500.2(d) is amended by adding a subparagraph (3) to read as follows:

(d) *Criteria for determining if your industrial unit is to be aggregated and is an MFBI.* * * *

(3) *Existing Units.* If you have two or more units on a single site, ERA will aggregate towards the 250 million BTUs per hour threshold any existing unit with a heat input rate equal to or greater than 50 million BTUs per hour.

PART 501—ADMINISTRATIVE PROCEDURES AND SANCTIONS

6. Section 501.33 is revised to read as follows:

§ 501.33 Requests for a public hearing.

In the case of a petition for an exemption from a prohibition imposed either by the Act or by a final rule or order issued by ERA to an existing facility under Title III of FUA, any interested person may submit a written request that ERA convene a public hearing in accordance with section 701 of FUA within 45 days after the notice of the filing of a petition is published in the Federal Register. In the case of a proposed prohibition rule or order, the 45 day period in which to request a public hearing shall commence upon the publication of the notice of availability of the Tentative Staff Report. This time limit may be extended at the discretion of ERA. Your request for a public hearing must include a description of your interest in the issue or issues involved, and an outline of the anticipated content of your presentation. Your request should, to the extent that you can, identify any witnesses that you contemplate presenting at the hearing and include, if possible, a summary of their anticipated testimony and of the purpose for that testimony.

7. Subpart E of Part 501 is amended by adding §§ 501.51 and 501.52 which read as follows:

Subpart E—Prohibition Rules and Orders

* * * * *

§ 501.51 Prohibition by order—Existing powerplants.

(a) ERA may prohibit by order the use of petroleum or natural gas as a primary energy source or in amounts in excess of the minimum amount necessary to maintain reliability of operation consistent with reasonable fuel efficiency in an existing powerplant if:

(1) That powerplant has not been identified as a member of a category subject to a final prohibition rule at the time of the issuance of such order.

(2) The requirements of section 504.5 have been met.

(3) You have not demontrated that you would have been granted an exemption for your powerplant if the prohibition had been established by rule. If your powerplant would have been granted a temporary exemption, however, ERA may issue you a final order which will take effect at such time as the temporary exemption would have terminated.

(4) In any case in which an order is not issued by reason of paragraph (a)(3) of this section, or in which the effective date of such order is delayed under such paragraph, ERA shall take such steps as may be necessary to assure the powerplant involved complies with the same requirements (including provisions of section 314(a) of FUA) as would have been applicable if an exemption had been granted based upon the grounds for which the order is not issued or the effective date is delayed.

(b) *Notice of order, and public participation.* (1) Prior to the issuance of a proposed order to an existing powerplant, ERA may hold a conference pursuant of § 501.32 of these regulations.

(2) Pursuant to section 701 of FUA, prior to the issuance of a final order to an existing powerplant, ERA shall publish a proposed order in the Federal Register, together with a statement of the reasons for the order. In the case of a proposed order that would prohibit the use of petroleum or natural gas as a primary energy source, the finding required by Section 302(a)(1) of the Act shall be published with such proposed order.

(3) ERA shall provide a period for the submission of written comments of at least three months after the date of the proposed order. During this period, the recipient of the proposed order and any other interested person must submit any evidence relating to each of the findings that ERA is required to make under Section 302(a) of the Act. A proposed order recipient will not be allowed to submit evidence relating to the findings which it did not submit during this three month period unless materials submitted after the period (i) could not have been submitted during the period through the exercise of due diligence, (ii) address material changes in fact or law occurring after the close of the period, or (iii) consist in amplification or rebuttal occasioned by the subsequent course of the proceeding. The order recipient must during this period identify any exemptions for which the unit in question may qualify, but the recipient need not during this period submit evidence attempting to demonstrate qualifications for the exemption. An extension of the three month time period may be granted in ERA's discretion.

(4) Subsequent to the end of the three month comment period, ERA will issue a notice of whether ERA intends to proceed with the Prohibition Order proceeding.

(5) An owner or operator of a powerplant that may be subject to an order may demonstrate prior to issuance of a final prohibition order that the powerplant would qualify for an exemption if the prohibition had been established by rule. Such demonstration shall be submitted within three months of the issuance of the notice of intention to proceed with the Prohibition Order. ERA will not delay the issuance of a final prohibition order or stay the effective date of such an order for the purpose of determining whether a proposed order recipient qualifies for a particular exemption unless the demonstration of qualification is submitted prior to or during the second three-month period, or unless materials submitted after the period (i) could not have been submitted during the period through the exercise of due diligence, (ii) address material changes in fact or law occurring after the close of the period, or (iii) consist in amplification or rebuttal occasioned by the subsequent course of the proceeding. An extension of this time period may be granted in ERA's discretion.

(6) Subsequent to the end of the second three month period, ERA will, if it intends to issue a final prohibition order, prepare and issue notice of availability of a tentative staff decision. Interested persons wishing a hearing must request a hearing within fourteen days after issuance of the notice of availability of the tentative staff decision.

(7) If a hearing has been requested, ERA shall provide interested persons with an opportunity to present oral data, views and arguments at a public hearing held in accordance with Subpart C of this part. Hearing will consider the findings which ERA must make in order to issue a final prohibition order and any exemption for which the proposed order recipient submitted its demonstration in accordance with subparagraph (5) of this paragraph.

(8) Upon request by the recipient of the proposed prohibition order, the combined public comment periods provided for in this section may be reduced to a minimum of 45 days from the time of publication of the proposed order.

(c) *Record and decision to issue a final order.* (1) ERA's record will consist of all relevant evidence presented at the public hearing, the written comments, and any other relevant information in the possession of ERA and made a part of the record of the proceeding. ERA will base its determination to issue an order on consideration of the whole record or those parts thereof cited by a party and supported by and in accordance with reliable, probative and substantial evidence.

(2) ERA shall include in the final order a written statement of the pertinent facts, a statement of the basis upon which the final order is issued, a recitation of the conclusions regarding the required findings and qualifications for exemptions. The final order shall state the effective date of the prohibition contained therein. If it is demonstrated that the facility would have been granted a temporary exemption, the effective date of the final order shall be delayed until such time as the temporary exemption would have terminated.

(3) ERA may enclose with a copy of the final order a schedule of steps that should be taken by a stated date (a compliance schedule) to ensure that the affected powerplant will be able to comply with the prohibitions stated in the order by the effective date. The compliance schedule may require the affected person to take steps with regard to a unit 60 days after service of the final order.

(4) A copy of the final order and a summary of the basis therefor will be published in the Federal Register. The order will become effective 60 days after issuance.

§ 501.52 Prohibition by order—Existing installations.

(a) ERA may prohibit by order the use of petroleum or natural gas as a primary energy source or in amounts in excess of the minimum amount necessary to maintain reliability of operation consistent with reasonable fuel efficiency in an existing major fuel burning installation if:

(1) That installation has not been identified as a member of a category subject to a final prohibition rule at the time of the issuance of such order.

(2) The requirements of § 506.2 have been met.

(3) You have not demonstrated that you would have been granted an exemption for your installation if the prohibition had been established by rule. If your installation would have been granted a temporary exemption, however, ERA may issue you a final order which will take effect at such time as the temporary exemption would have terminated.

(4) In any case in which an order is not issued by reason of paragraph (a)(3) of this section, or in which the effective date of such order is delayed under such paragraph, ERA shall take such steps as may be necessary to assure the installation involved complies with the same requirements (including provisions of section 314(a) of FUA) as would have been applicable if an exemption had been granted based upon the grounds for which the order is not issued or the effective date is delayed.

(b) *Notice of order, and public participation.* (1) Prior to the issuance of a proposed order to an existing installation, ERA may hold a conference pursuant to § 501.32 of these regulations.

(2) Pursuant to section 701 of FUA, prior to the issuance of a final order to an existing installation, ERA shall publish a proposed order in the Federal Register, together with a statement of the reasons for the order. In the case of a proposed order that would prohibit the use of petroleum or natural gas as a primary energy source, the finding required by Section 302(a)(1) of the Act shall be published with such proposed order.

(3) ERA shall provide a period for the submission of written comments of at least three months after the date of the proposed order. During this period, the recipient of the proposed order and any other interested person must submit any evidence relating to each of the findings that ERA is required to make under Section 302(a) of the Act. A proposed order recipient will not be allowed to submit evidence relating to the findings which it did not submit during this three month period unless materials submitted after the period (i) could not have been submitted during the period through the exercise of due diligence, (ii) address material changes in fact or law occurring after the close of the period, or (iii) consist in amplification or rebuttal occasioned by the subsequent course of the proceeding. The order recipient must during this period identify any exemptions for which the unit in question may qualify, but the recipient need not during this period submit evidence attempting to demonstrate qualifications for the exemption. An extension of the three month time period may be granted in ERA's discretion.

(4) Subsequent to the end of the three month comment period, ERA will issue a notice of whether ERA intends to proceed with the Prohibition Order proceeding.

(5) An owner or operator of an installation that may be subject to an order may demonstrate prior to issuance of a final prohibition order that the installation would qualify for an exemption if the prohibition had been established by rule. Such demonstration

shall be submitted within three months of the issuance of the notice of intention to proceed with the Prohibition Order. ERA will not delay the issuance of a final prohibition order or stay the effective date of such an order for the purpose of determining whether a proposed order recipient qualifies for a particular exemption unless the demonstration of qualification is submitted prior to or during the second three-month period, or unless materials submitted after the period (i) could not have been submitted during the period through the exercise of due diligence, (ii) address material changes in fact or law occurring after the close of the period, or (iii) consist in amplification of rebuttal occasioned by the subsequent course of the proceeding. An extension of this time period may be granted in ERA's discretion.

(6) Subsequent to the end of the second three month period, ERA will, if it intends to issue a final prohibition order, prepare and issue notice of availability of a tentative staff decision. Interested persons wishing a hearing must request a hearing within fourteen days after issuance of the notice of availability of the tentative staff decision.

(7) If a hearing has been requested ERA shall provide interested persons with an opportunity to present oral data, views and arguments at a public hearing held in accordance with Subpart C of this part. The hearing will consider the findings which ERA must make in order to issue a final prohibition order and any exemption for which the proposed order recipient submitted its demonstration in accordance with subparagraph (5) of this paragraph.

(8) Upon request by the recipient of the proposed prohibition order, the combined public comment periods provided for in this section may be reduced to a minimum of 45 days from the time of publication of the proposed order.

(c) *Record and decision to issue a final order.* (1) ERA's record will consist of all relevant evidence presented at the public hearing, the written comments, and any other relevant information in the possession of ERA and made a part of the record of the proceeding. ERA will base its determination to issue an order on consideration of the whole record or those parts thereof cited by a party and supported by and in accordance with reliable, probative and substantial evidence.

(2) ERA shall include in the final order a written statement of the pertinent facts, a statement of the basis upon which the final order is issued, a recitation of the conclusions regarding the required findings and qualifications for exemption. The final order shall state the effective date of the prohibition contained therein. If it is demonstrated that the facility would have been granted a temporary exemption, the effective date of the final order shall be delayed until such time as the temporary exemption would have terminated.

(3) ERA may enclose with a copy of the final order a schedule of steps that should be taken by a stated date (a compliance schedule) to ensure that the affected installation will be able to comply with the prohibitions stated in the order by the effective data. The compliance schedule may require the affected person to take steps with regard to a unit 60 days after service of the final order.

(4) A copy of the final order and a summary of the basis therefor will be published in the Federal Register. The order will become effective 60 days after issuance.

PART 503—NEW ELECTRIC POWERPLANTS

8. Section 503.5(d)(i)(B) is amended by adding a footnote No. 14 to read as follows:

§ 503.5 Cost calculations for new powerplants.

(d) *Information on parameters used in the calculation.* * * *

(4)(i) * * *

(B) Determine the incremental increase in case outlays for operations and maintenance expenses and fuel expenses that would occur in your region by the addition of the power plant.[14] * * *

9. Section 503.22(a)(3) is amended to read as follows:

§ 503.22 Site limitations.

(a) * * *

(3) Adequate land or facilities for handling, using or storing an alternate fuel would be unavailable;

* * * * *

10. Section 503.33(a)(3) is amended to read as follows:

§ 503.33 Site limitations.

(a) * * *

(3) Adequate land or facilities for handling, using or storing an alternate fuel would be unavailable;

* * * * *

In 10 CFR, Chapter II, Subchapter E, Part 504, §§ 504.2, 504.3, and 504.5 in Subpart B, and Subparts C, D, and E and Part 506 are revised to read as follows:

PART 504—EXISTING ELECTRIC POWERPLANTS

Subpart A—Restrictions on the Use of Petroleum

Sec.
504.1 Prohibition against the increased use of petroleum.[1]

Subpart B—Prohibitions and System Compliance Option

504.2 Purpose and scope.
504.3 Statutory prohibitions.
504.4 Electric utility system compliance option.[2]
504.5 Prohibitions by order (case-by-case).

Subpart C—General Requirements for Exemptions

504.10 Purpose and scope.
504.11 Fuels Decision Report.
504.12 Cost calculation for existing powerplants.
504.13 No alternative power supply—general requirement for permanent exemptions.
504.14 [Reserved].
504.15 Use of mixtures—general requirement for permanent exemptions.
504.16 Use of fluidized bed combustion not feasible—general requirement for permanent exemptions.
504.17 Terms and conditions; compliance plans.

Subpart D—Temporary Exemptions for Existing Powerplants

504.20 Purpose and scope.
504.21 Lack of alternate fuel supply.
504.22 Site limitations.
504.23 Inability to comply with applicable environmental requirements.
504.24 Future use of synthetic fuels.
504.25 Use of innovative technologies.
504.26 Public interest exemption.
504.27 Retirement.
504.28 Temporary exemption for powerplants necessary to maintain reliability of service.
504.29 Peakload powerplants.

Subpart E—Permanent Exemptions for Existing Powerplants

504.30 Purpose and scope.
504.31 Lack of alternate fuel supply.
504.32 Site limitations.
504.33 Inability to comply with applicable environmental requirements.
504.34 State or local requirements.
504.35 Cogeneration.
504.36 Permanent exemption for certain fuel mixtures containing natural gas or petroleum.
504.37 Emergency purposes.
504.38 Peakload powerplants.
504.39 Intermediate load powerplants.
504.40 Use of natural gas by powerplants with capacity of less than 250 million BTUs per hour.
504.41 Use of liquefied natural gas.

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[14] When using the method specified in § 503.5(d)(4)(i)(B), if the cost of using imported oil as computed by equation 2 or 5 is zero or negative, the determination of substantially exceeds will be on a case-by-case basis.

[1] Issued May 8, 1979 (44 FR 28595, May 15, 1979.)
[2] Issued June 12, 1979 (44 FR 36002, June 20, 1979.)

Authority: Department of Energy Organization Act, Pub. L. 95-91, 91 Stat. 565 (42 U.S.C. 7101 et seq.); Powerplant and Industrial Fuel Use Act of 1978, Pub. L. 95-620 Stat. 3289 (42 U.S.C. 8301 et seq.); E.O. 12009, (42 FR 46267).

PART 504—EXISTING ELECTRIC POWERPLANTS

* * * * * [1]

Subpart B—Prohibitions and System Compliance Option

§ 504.2 Purpose and scope.

This subpart sets forth the statutory prohibitions imposed on existing electric powerplants. The prohibitions set forth in this subpart apply to all existing electric powerplants, as defined in § 500.2 unless an exemption has been granted by ERA under Subparts D and E of this part. Any person who owns, controls, rents, or leases a powerplant is subject to the prohibitions imposed and the sanctions provided for by the Act or these regulations.

§ 504.3 Statutory prohibitions.

(a) Section 301(a)(1) of the Act prohibits the use of natural gas as a primary energy source by any existing electric powerplant on or after January 1, 1990, unless, and to the extent that, the powerplant is granted either a temporary or permanent exemption under this part or a System Compliance Option has been approved.

(b) Section 301(a)(2) of the Act prohibits the use of natural gas as a primary energy source in any existing electric powerplant before January 1, 1990 unless it used natural gas as a primary energy source any time during calendar year 1977, or unless, and to the extent that, the powerplant is granted either a temporary or permanent exemption under subpart D or E of this part.

(c) Section 301(a)(3) of the Act prohibits the use of natural gas as a primary energy source in any existing electric powerplant, in any calendar year before 1990, in greater proportions than the average yearly proportion of natural gas which:

(1) The powerplant used as a primary energy source in calendar years 1974 through 1976; or

(2) If the powerplant began operations on or after January 1, 1974, the powerplant used as a primary energy source during the first two calendar years of its operation.

(d) Any prohibition against your use of natural gas or after January 1, 1990 will be stayed while any petition you have filed for an exemption is resolved. The stay will include the time required for judicial review. Your petition for exemption may be filed at any time after May 8, 1979, the effective data of FUA, but it must be filed at least one year before the date the prohibition is first to take effect.

* * * * * [1]

§ 504.5 Prohibitions by order (case-by-case).

(a) ERA may prohibit, by order, the use of natural gas or petroleum as a primary energy source in an existing electric powerplant if ERA finds that:

(1) The powerplant has, or previously had, the technical capability to use an alternate fuel as a primary energy source;

(2) The powerplant has this technical capability, or it could have the technical capability again without:

(i) A substantial physical modification of the powerplant; or

(ii) A substantial reduction in the rated capacity of the powerplant; and

(3) It is financially feasible for the powerplant to use alternate fuel as its primary energy source.

(b) ERA must make a proposed finding regarding the technical capability of a unit to use alternate fuel as identified in paragraph (a)(1) of this section prior to the date of publication of the notice of the proposed prohibition. ERA will publish this finding in the Federal Register along with the notice of the proposed prohibition.

(c) The findings enable ERA to assess the potential impact of a prohibition order on three levels: the impact on the facility itself, the impact on the economic activity which the steam or electric power supports, and the impact on the parent firm owning the site. Where the regulation reflects an emphasis on one level or another in a particular finding, ERA has based such emphasis on the terms of the legislation, the conference report, and its own identification of the most appropriate level in accordance with its regulatory discretion.

(d) *Technical capability.* (1) ERA will consider "technical capability" on a case-by-case basis. In making this assessment however, ERA will only consider the characteristics of the unit itself and will not ordinarily consider the nature or absence of appurtenances outside the unit. ERA's major concern is the ability of the unit, from the point of fuel intake, to physically sustain combustion of a given fuel and to maintain heat transfer.[1]

(2) ERA considers that a unit "had" the technical capability to use an alternate fuel if the unit was once able to burn that fuel (regardless of whether the unit was expressly designed to burn that fuel or whether it ever actually did burn it) but is no longer able to do so at the present due to temporary or permanent alterations to the unit itself.[2]

(3) A unit "has" the technical capability to use an alternate fuel if it can burn an alternate fuel, notwithstanding the fact that minor adjustments must be made to the unit beforehand or that pollution control equipment may be required to meet air quality requirements.[3]

(e) *Substantial physical modification.* ERA will make its determination on whether a physical modification to a unit is "substantial" on a case-by-case basis. ERA will consider physical modifications made to the unit as "substantial" where warranted by the magnitude and complexity of the engineering task or where the modification would impact severely upon operations at the site.[4] ERA will not, however, assess physical modifications on the basis of cost or the installation of pollution control or fuel handling equipment.

(f) *Substantial reduction in rated capacity.* (1) ERA will assess units for

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[1] Subpart A, § 504.1 *Prohibition against the increased use of petroleum.* (Published 44 FR 28595, May 15, 1979).

[1] § 504.4 *Electric utility system compliance option.* (Published 44 FR 36002, June 20, 1979.)

[1] For example, ERA will examine the furnace configuration and ash removal capability but will not normally consider the need to install pollution control equipment as a measure of technical capability. Furthermore, ERA will not conclude that the absence of fuel handling equipment, such as conveyor belts, pulverizers, or unloading facilities, bears on the issue of a unit's "technical capability" to burn an alternate fuel.

[2] For example, a unit which at one time burned solid coal, but which could no longer do so because its coal firing ports and sluicing channels had been cemented over, would be classified as having "had" the technical capability to use coal. (The question of whether it again "could have" such capability without "substantial physical modification" is a separate and additional question.)

[3] A unit designed to burn natural gas also "has" the technical capability to burn medium Btu gas from coal (assuming such gas is available). Also, a unit designed to burn oil may, depending upon the chemical characteristics, be a unit that "has" the technical capability to burn liquefied coal. The fact that certain minor adjustments may be necessary does not render this a "hypothetical" as opposed to a "real" capability. Even an oil fired unit converting from the use of #2 distillate to #6 residual oil may be required to adjust or replace burner nozzles and add soot blowers. ERA views these alterations as minor adjustments the need for which does not render a unit incapable of burning a particular fuel.

[4] Significant alterations affecting the furnace configuration or a complete respacing of the tubes would likely fall into this category. A combination of modifications involving changes required for bottom ash removal, related construction and engineering work, and other modifications to the boiler, other than furnace configurations or tube spacing may, in some circumstances, cause modifications to be considered substantial.

which a derating of 10% or more is claimed on a case-by-case basis. ERA does not consider a derating of less than 10% as a result of converting a unit from oil or gas to an alternate fuel to be "substantial" under any circumstances.[5]

(2) In assessing whether unit deratings of 10% or more are "substantial", ERA will consider the impact of the reduction in available capacity on the system as well as on the unit itself.[6]

(g) *Financial feasibility.* (1) It is financially feasible for your powerplant to use an alternate fuel as its primary energy source if: the cost of using an alternate fuel does not substantially exceed the cost of using imported petroleum using the general cost calculation described in § 504.12 (a) and (b) of the regulations. However, in making this cost-calculation, ERA will use your firm's real cost of capital[7] as the discount rate for the purpose of computing cost, rather than the average, real cost of capital required for powerplants as specified in § 504.12 of these regulations, and

(2) You may seek to rebut this presumption by evidence that despite good faith efforts you are unable to raise the capital that would be necessary for the conversion, or that for some other economic or financial reason, conversion is not financially feasible. The standard for assessing capital availability will be identical to that specified in § 503.35 (inability to obtain adequate capital).

(3) In making this determination, ERA will consider the impact of the conversion, including other conversions which are or may be imposed upon the utility system by the Act.

(h) *Mixtures Finding.* (1) If ERA finds that it is technically and financially feasible for your powerplant to use a mixture of petroleum or natural gas and alternate fuel as its primary energy source, ERA may prohibit you, by order, from using petroleum or natural gas in amounts exceeding the minimum amount necessary to maintain the reliability of your operation consistent with maintaining reasonable fuel efficiency of the mixture.

(2) In making the technical feasibility finding, ERA may weigh "physical modification" or "derating of the unit;" but these considerations, by themselves, will not control the technical feasibility finding. A technical feasibility finding might be made notwithstanding the need for substantial physical modification. The economic consequences of a substantial physical modification are taken into account in determining financial feasibility.

(3) The authority of ERA implemented under this section should not be confused with the two other fuel mixture provisions of these regulations. One is the requirement that petitioners for permanent exemptions need demonstrate that the use of a mixture of natural gas or petroleum and an alternate fuel is not economically or technically feasible (§§ 504.15 and 506.14). The second is the permanent fuel mixtures exemptions themselves (see §§ 504.36 and 506.36).

[5] Typically, units that are the subject of a prohibition order will not have installed any operating air pollution control equipment sufficient to burn coal in compliance with applicable environmental equipments. The installation and use of air pollution control equipment alone can, in many cases, produce a derating of close to 10 percent. Moreover, the shift to coal itself will, because of differences in energy density and fuel flow characteristics typically involve some derating. Thus if a derating of less than 10 percent could constitute a "substantial" derating, the authority conferred by Congress to prohibit by order could be almost entirely nugatory.

[6] For example, ERA may find that the derating of a unit far in excess of 10 percent is not "substantial" if it produces no appreciable effect upon the operations of a facility with considerable excess capacity.

[7] For the purposes of these interim regulations, you must compute the real cost of capital according to the procedures outlined in Appendix I of these regulations.

Subpart C—General Requirements for Exemptions

§ 504.10 Purpose and scope.

This subpart establishes the general requirements necessary to qualify for either a temporary or permanent exemption from the prohibitions set out under this part and establishes the methodology for calculating the cost of using an alternate fuel and the cost of using imported petroleum.

§ 504.11 Fuels Decision Report.

(a) Before ERA will accept a petition for either a temporary or permanent exemption from a final statutory prohibition or prohibition order issued under this part, you must include as part of your petition a Fuels Decision Report as described in Part 502 unless you are requesting an emergency or retirement exemption. The Fuels Decision Report shall contain the analysis and documentation of the evidence required in support of your exemption request.

(b) Your petition may contain more than one exemption request. In this case, your petition would include one Fuels Decision Report which addresses your considerations and the appropriate forms for the exemptions you are requesting.

§ 504.12 Cost calculations for existing powerplants.

(a) *General.* (1) This calculation compares the cost of using alternate fuel to the cost of using imported petroleum. Its purpose is to provide ERA with a mechanism for deciding when investments that are not the best economic choice from the viewpoint of the individual firm are nevertheless economic in light of the benefits and costs to the United States.

(2) The cost of using an alternate fuel in lieu of imported petroleum as a primary energy source will be deemed to be substantially in excess of the cost of using imported petroleum where the ratio of the former to the latter is greater than the index set periodically by ERA.

(3) The index is currently 1.3. ERA will revise the index from time to time after public notice and an opportunity to comment. Revisions shall become effective for all ERA decisions after final publication; however, the relevant index for a specific petition will be the index in effect at the time the petition is submitted, or the index in effect at the time a decision is rendered, whichever is lower.

(4) The cost test takes into consideration cash outlays for capital investments and annual expenses, and the effect of depreciation and taxes on cash flow. There are two comparative cost tests—a general cost test and a special cost test. You must demonstrate eligibility for a permanent exemption using the procedures specified in the general cost test (section b). You must demonstrate eligibility for a temporary exemption using the procedures specified in the general cost test (section b) or the special cost test (section c).

(5) The general cost test differs from the special cost test with respect to the time period over which costs are calculated. When using the general cost test, the cost must be computed for the remaining useful life of the powerplant. When using the special cost test, the cost is computed only for the term of the exemption.

(b) *Cost calculation—general cost test.* (1) You may be eligible for a permanent exemption if you demonstrate that the cost of using an alternate fuel starting with each successive year within the first 10 years of the exemption will always substantially exceed the cost of using imported petroleum from the time the exemption becomes effective until the end of the powerplant's remaining useful life. You will have to show that the cost of using an alternate fuel, starting in each of the first 10 years of this exemption and using oil or natural gas until the start of using an alternate fuel, substantially exceeds the cost of using only imported petroleum.

(2) If the discounted lifetime cost of alternate fuel use, computed with successive starting date for the first 10 years of the exemption, does not always substantially exceed the cost of using imported petroleum, you would only be eligible for a temporary exemption. The length of the temporary exemption would be for the minimum period where the cost of starting to use alternate fuel always substantially exceeds the cost of using imported petroleum. For example, if you can burn coal and it cannot be obtained at a reasonable price for 2 years, ERA may grant a temporary exemption and allow the burning of oil for 2 years.

(3) To conduct the test, you must use the equations that follow.

(i) Calculate the ratio (R) of the cost of using an alternate fuel to the cost of using imported petroleum with equation 1.

$$\text{EQ 1} \qquad R = \frac{\text{COST (ALTERNATE)}}{\text{COST (OIL)}}$$

(ii) Calculate the cost of using an alternate fuel and imported petroleum with equation 2.

$$\text{EQ 2} \qquad \text{COST} = I + \sum_{i=1}^{N} \frac{(OM_i + FL_i)(1 - t) - t(DPR_i)}{(1 + K)^i}$$

(iii) Calculate the capital investment using equation 3.

$$\text{EQ 3.} \quad I = I_D + \sum_{i=-g}^{N} \frac{I_i - ITC_i - S_i}{(1 + K)^i}$$

(4) The terms in equations 2 and 3 are defined as follows:

i=Year. Outlays before the proposed exemption becomes effective are future valued to the year before the proposed exemption becomes effective (year 0) and outlays after the proposed exemption becomes effective are present valued to the year before the proposed exemption becomes effective.

g=The number of years prior to the year before the proposed exemption becomes effective a cash outlay is made for capital investments or investment tax credit is used.

N=The remaining useful life of the powerplant (see section d).

I_D=Capital investment required to recover capacity lost due to derating (see section d).

I_i=Yearly cash outlay (in dollars) from the year outlays first occur to the last year of the plant's remaining useful life for capital investments (see section d).

OM_i=Annual cash outlay in year i (in dollars) for all operations and maintenance expenses except fuel (i.e., all non-capital and non-fuel cash outlays caused by putting the capital investments into service). May include labor, materials, insurance, taxes (except income taxes), etc. (See section d.)

S_i=Salvage value of capital investments (in dollars) realized in year i

FL_i=Annual cash outlay for delivered fuel expenses (in dollars) in year i (see section d).

K=The discount rate expressed as a fraction (see section d).

ITC_i=Federal investment tax credit resulting from capital investments used in year i (see section d).

DPR_i=Depreciation in year i (see section d).

t=Marginal income tax rate (see section d).

(5) The step-by-step procedure that follows shows the comparison that you must make. It outlines the fuel and time comparisons.

(i) Compute the cost (COST) of using an alternate fuel throughout the remaining useful life of the powerplant with equation 2.

(ii) Compute the cost (COST) of using oil or natural gas throughout the remaining useful life of the powerplant with equation 2.

(iii) Compute the ratio (R) of the cost of using an alternate fuel throughout the remaining useful life of the powerplant to the cost of using oil or natural gas throughout the remaining useful life of the powerplant with equation 1. If the ratio (R) is equal to or less than 1.3, the index set by ERA, you are not eligible for a permanent or temporary exemption using the general cost test and need not complete the remainder of the calculation.

(iv) Compute the cost (COST) of using an alternate fuel with equation 2 assuming an alternate fuel is not used as the primary energy source until the end of the first year of the exemption and that oil or natural gas is used for the first year of the exemption. All cash outlays should reflect postponed use of alternate fuel (e.g., installation of scrubber when used).

(v) Successively compute the cost (COST) of using an alternate fuel with equation 2 assuming alternate fuel is postponed until the end of the second through tenth year of the exemption (and oil or natural gas is used in the years preceding alternate fuel use).

(vi) Compute the ratios (R) of the cost of using an alternate fuel successively at the end of the first through tenth year (and using oil or natural gas in the years preceeding alternate fuel use) to the cost of using oil or natural gas throughout the remaining useful life of the powerplant with equation 1.

(vii) If all the ratios (R) computed in iii and vi are greater than 1.3 (an index to be set periodically by ERA), a permanent exemption would be granted. If one or more of the ratios (R) is equal to or less than 1.3 and a series of ratios (R), starting with the case where alternate fuel is used from the start of the exemption, are all greater than 1.3, a temporary exemption would be granted for the minimum period in which the cost of starting to use alternate fuel, deferred year by year, always exceeds 1.3.

(6) The following table shows the hypothetical results of four sets of calculations, assuming the index set by ERA is 1.3.

Hypothetical Results of Four Sets of Calculations

Year in which alternate fuel use commences	Case I	Case II	Case III	Case IV
At start of exemption	1.4	1.6	1.5	1.1
End of Year:				
1	1.4	1.6	1.5	1.1
2	1.5	1.7	1.5	1.2
3	1.3	1.6	1.4	1.2
4	1.3	1.5	1.3	1.1
5	1.2	1.5	1.4	1.1
6	1.2	1.4	1.4	1.1
7	1.1	1.4	1.5	1.1
8	1.1	1.4	1.5	1.1
9	1.0	1.4	1.6	1.1
10	1.0	1.4	1.6	1.1

The results of the above table show that: a 2-year temporary exemption would be granted in Case I, a permanent exemption would be granted in Case II, a 3-year temporary exemption would be granted in Case III, and no exemption would be granted in Case IV.

(c) *Cost calculations—special cost test.* (1) You may be eligible for a temporary exemption if you demonstrate that the cost of using an alternate fuel will substantially exceed the cost of using oil or natural gas over the period of the proposed exemption. The period of the exemption cannot exceed 10 years. You will have to show that the cost of using an alternate fuel substantially exceeds the cost of using imported petroleum for the first year of the exemption, the first 2 years of the exemption, and successive first years of the exemption, up to the period of the proposed exemption. To do so, you must perform the calculations with successive ending dates to determine the maximum length of the exemption. ERA will limit the duration of a temporary exemption to the shortest time possible.

(2) To conduct the test, you must use the equations that follow.

(i) Calculate the ratio (R) of the cost of using an alternate fuel to the cost of using imported petroleum with equation 4.

$$\text{EQ 4} \qquad R = \frac{\text{COST (ALTERNATE)}}{\text{COST (OIL)}}$$

(ii) Calculate the cost using equation 5.

$$\text{EQ 5} \qquad \text{COST} = I \times \frac{\sum_{i=1}^{P}(1+K)^{-i}}{\sum_{i=1}^{N}(1+K)^{-i}} + \sum_{i=1}^{P} \frac{(OM_i + FL_i)(1-t) - t(DPR_i)}{(1+k)^i}$$

(3) The terms in equation 5 are the same as in equation 2 above with the addition of:

P=The length of the proposed temporary exemption.

(4) The step-by-step procedure that follows shows the comparisons you must make.

(i) Compute the cost (COST) of using an alternate fuel assuming the length of the proposed exemption is 1 year with equation 5.

(ii) Compute the cost (COST) of using oil or natural gas assuming the length of the proposed exemption is 1 year with equation 5.

(iii) Compute the ratio (R) of the cost of using an alternate fuel for the first year to the cost of using imported petroleum for the first year with equation 4.

(iv) Repeat the calculations made in i, ii, and iii above assuming the length of the proposed exemption is 2 years, 3 years, 4 years, and so on, up to the period of the proposed exemption.

(v) A temporary exemption would be granted when all the ratios (R) are greater than 1.3 (the index established by ERA).

(d) *Information on parameters used in the calculation.* (1) All estimated expenditures, except natural gas, and petroleum products, shall be expressed in real (uninflated) terms by using the prices in effect at the time the petition is submitted.

(2) The delivered price of oil or natural gas used in the calculation of delivered fuel expenses must reflect the price of imported oil.

(i) If you use 100 percent domestic [8] petroleum product in your facility, compute your petroleum product price with equation 6.

$$\text{EQ 6} \qquad PFE = PF + PICO - PCCO$$

The terms of equation 6 are defined as follows:

PICO=Price of imported crude oil. The most recent refiner acquisition cost of imported crude oil as reported in the Federal Register monthly notice for the DOE Domestic Crude Oil Allocation (Entitlements) Program.

PCCO=Price of composite crude oil. The most recent weighted average cost of total reported crude oil receipts as reported in the Federal Register notice for the DOE Entitlements Programs.

PF=Price of your fuel (f.o.b. your facility). The most recent actual weighted average cost of your fuel (other than natural gas). Alternatively, if no purchases of fuel oil occurred, or you used natural gas during that month, you should use a simple average of the industrial price of fuel oil (capable of being burned in your facility) sold in your area by at least three suppliers.

PFE=Price of fuel for use in the cost calculation.

(ii) If you use 100 percent imported petroleum product in your facility, compute your petroleum price with the following equation:

$$\text{EQ 7} \qquad PFE = PF + ENT$$

The terms of equation 7 are the same as equation 6 with the addition of:

ENT=$\frac{1}{2} \times E_p \times$DOSR For residual fuel oil if an entitlement has been received by the importer.

ENT=O For all other products or if an entitlement has not been received by the importer.

where

E_p=Entitlement price reported in the Federal Register monthly notice for the DOE Entitlements Program.

(iii) If you use a combination of domestic and imported petroleum product in your facility, you may use the price computed with the formula in paragraph (d)(2)(i) of this section or you may use a weighted average of the prices computed with the formulas in paragraph (d)(2) (i) and (ii) of this section.

(iv) If you use natural gas in your facility, you must use the formula in paragraph (d)(2)(i) of this section and the price of No. 6 residual fuel oil, which meets the air quality standards in your area, as the price of fuel.

(3) Capital investment yearly cash outlays (I_i) must include all items which are captial investments for Federal income tax purposes. All purchased equipment which has a useful life greater than 1 year, capitalized engineering costs, land, construction, environmental offsets, fuel inventory,[9] etc., required to use the powerplant being converted after the proposed exemption would become effective must be included. However, an item may only be included if a cash outlay is required after the decision has been made to convert (or not to convert) the powerplant.

(4) (i) Capital investment, if any, required to recover the lost capacity due to derating (I_D) must be computed with equation (8) if an election is made to recover that capacity.[10]

$$\text{EQ 8} \qquad I_D = \frac{\sum_{i=1}^{N}(1+K)^{-i}}{\sum_{i=1}^{M}(1+K)^{-i}} \times \sum_{i=-8}^{M} \frac{I_i^D - ITC_i^D - S_i^D}{(1+K)^i}$$

(ii) M, I_i^D, ITC_i^D and S_i^D are the useful life, yearly investment cash outlays, investment tax credits, and salvage values respectively resulting from the purchase of equipment required to recover the capacity lost due to derating; all definitions and information which applies to N, I_i, ITC_i, and S_i, apply to M, I_i^D, ITC_i^D and S_i^D except that M, I_i^D, ITC_i^D and S_i^D are limited to equipment required to recover the capacity lost due to derating. All other terms are as in equation 3.

(iii) If an election is made not to recover the capacity lost due to derating, the capital investment required due to derating equals zero.

(5)(i) The annual operations and maintenance expenses (OM_i) and the fuel expenses (FL_i) are computed by one of two methods; however the one chosen must be applied consistently throughout the analysis. They are:

(A) Assume the powerplant will annually generate an amount of electrical energy equal to the average amount of electrical energy generated for the last five years (or the life of the powerplants if it is less than 5 years)

[8] For the purposes of the regulation, the Virgin Islands, Puerto Rico, and the U.S. Territories and possessions are domestic sources.

[9] The following fuel supplies must be included: (a) All powerplants with only steam driven turbines—78 days, (b) all powerplants with only combustion turbines—162 days, and (c) all powerplants with combined cycles—both steam driven turbines and combustion turbines—162 days. If the you already have oil in inventory, it must be salvaged.

[10] If the capacity is recovered, the cash flows must result in the least cost feasible solution (i.e., the cost computed with equation 2 or 5 must be the lowest feasible cost).

when computing the annual operations and maintenance and fuel expenses.

(B) Determine the incremental change in cash outlays for operations and maintenance expenses and fuel expenses in your region due to the powerplant under consideration.[11] First economically dispatch all powerplants in the region except the powerplant in which conversion to alternate fuel is being considered (do not dispatch that plant at all). Then economically dispatch all powerplants in the region including the powerplant in which conversion to alternate fuel is being considered and, it applicable, the additional powerplant required due to the derating of the powerplant being converted. The difference in cash outlays for operations and maintenance expenses and fuel expenses is (*1*) the incremental change in cash outlays for operations and maintenance expenses and fuel expenses in you region and (*2*) the operations and maintenance expenses and fuel expenses for the purposes of the cost calculation.[12] The region must be your electrical region unless you can show such integrated operation is unlikely to be achieved midway through the remaining useful life of the powerplant and you can propose an acceptable alternative.

(ii) If you use the methodology set out in paragraph (d)(5)(i)(A) of this section the operations and maintenance expenses must include both the fixed and variable components.

(iii) If you use the methodology set out in paragraph (d)(5)(i)(B) of this section, you will have to certify, subject to penalties, that the proposed plant will not use more oil than you showed it would use in the dispatch analysis.

(6) The discount rate (K) is 2.9 percent. ERA will change the discount rate from time to time after public notice and an opportunity to comment. Revisions shall become effective after final publication; however, the relevant discount rate for a specific petition will be the discount rate in effect at the time the petition is submitted.

(7) The remaining useful life (N) of a coal, oil or natural gas capable powerplant will be 35 years minus the number of years of operation prior to the effective date of the proposed exemption. The useful life of other alternate fuel powerplants shall be presumed to be 35 years minus the number of years of operation prior to the effective date of the exemption. You may rebut this presumption with suitable engineering evidence.

(8) All Federal investment tax credit (ITC_i) will be applied consistently throughout the analysis in a manner consistent with Federal tax laws in effect at the time the petition is submitted.

(9) Depreciation (DPR_i) will be applied consistently throughout the analysis in a manner consistent with the Federal tax laws in effect at the time the petition is submitted. Depreciation on both the original plant and the capital investment required due to the conversion must be included. In general, accelerated depreciation cannot be used for new gas or oil-fired boilers. You must use the most rapid depreciation permitted by law for capital investments required to burn alternate fuel.

(10) The marginal income tax rate (t) is the firm's marginal Federal income tax rate for the year the petition is submitted.

(11) All estimated cash outlays will be computed in accordance with generally accepted accounting principles.

(e) *Evidence in support of the comparative cost test.* All petitions for exemption requiring the use of the comparative cost test shall include, but not be limited to, the following information:

(1) A detailed accounting of all cash outlays, investment tax credits, and anticipated salvage value for capital investments. Include a description and cost estimate of all major construction and equipment. All critical assumptions should be stated and sufficient data should be included to support your estimates.

(2) A detailed accounting of all annual cash outlays for fixed and variable operations and maintenance expenses including a description of all major elements and the formulas used to compute them. All critical assumptions should be stated and sufficient data included to support your estimates.

(3) A detailed accounting of all annual cash outlays for delivered fuel expenses including the formulas used to compute them. All critical assumptions should be stated and sufficient data included to support your estimates. The fuel price and characteristics for each alternate fuel should be included.

(4) If the remaining useful life of an alternate fuel—other than coal—capable powerplant is judged to be less than 35 years minus the number of years of operation prior to the effective date of the proposed exemption, all critical assumptions and sufficient data to support that position.

(5) A detailed accounting of the depreciation for each capital asset, including the depreciable base, tax life, and methods used. All critical assumptions should be stated and sufficient data submitted to support your estimates.

(f) *Example of calculations.* (1) The purpose of this example is solely to illustrate the mechanics of the cost tests; it should not be construed to be guidance on the application of the Federal income tax laws. The detail is only to the level of the individual terms in the cost test equations. Where the petitioner should supply a value, equations and data, we have only supplied the value.

(2) We are assuming that you are profitable to the extent that your Federal marginal income tax rate is 46 percent and that you need not carry over investment tax credits.

(3) You are considering converting an oil fired powerplant to coal. In this particular situation, the delivery cost of coal is much greater for the first 3 years than it will be in the later years because of a transportation problem requiring 3 years to resolve. Do you qualify for an exemption? If so, is it permanent or, temporary?

(4) To determine if you qualify for a permanent exemption, you would have to use the general cost test and compute the ratios of the cost to use (i) coal for the remaining useful life of the powerplant, (ii) oil for the first year of the exemption and coal for the remainder of the remaining useful life of the powerplant, (iii) oil for the first 2 years of the exemption and coal for the remainder of the remaining useful life of the powerplant * * * and (iv) oil for the first 10 years of the exemption and coal for the remainder of the remaining useful life of the powerplant to the cost of using oil for the entire remaining useful life of the powerplant.

(5) All 11 ratios would have to be higher than 1.3, which is the index for the purposes of this example, in order to qualify for a permanent exemption. However, if a series of successive ratios, starting with the case where alternate fuel is used from the start of the exemption, are all greater than 1.3, you would be eligible for a temporary exemption up to the last year the ratio is greater than 1.3.

(6) In this example, we will only compute the ratios of (i) the cost to use coal for the remaining useful life of the powerplant and (ii) the cost to use oil for the first 3 years of the exemption and

[11] If the capacity lost due to derating is recovered, you must use this method and the cash flows must result in the least cost feasible solution (i.e., the cost computed with equation 2 or 5 must be in lowest feasible cost).

[12] When using the method specified in § 504.12(d)(5)(i)(B), the cost of using imported oil as computed by equation 2 or 5 is zero or negative, the determination of substantially exceeds will be made on a case-by-case basis.

coal for the remainder of the remaining useful life of the powerplant to the cost of using oil for the entire remaining useful life of the powerplant.

(7) To determine if you qualify for a temporary exemption, if you have not already done so with the General Cost Test, of 3 years, you would have to use the Special Cost Test and compute the ratios of the cost to use coal to the cost to use oil for 1, 2, and 3 years. All three ratios would have to be higher than 1.3 in order to qualify for a 3-year temporary exemption. In this example, we will only compute the ratio of the cost to use coal to the cost to use oil for 3 years.

(8) *Parameters.* A set of hypothetical parameters are given below. The powerplant has a capacity of 500 MW.

(i) *Capital cash flow requirements.* The cash flows required to make the plant coal capable are:

Years before powerplant becomes coal capable	Cash flow
—1	$49,927,000
0	24,963,000
Total	$74,890,000

It is assumed this is all pollution control equipment.

(ii) *Operations and maintenance expense cash flow requirements.*

(A) When burning oil:

Fixed	$1,048,000/yr
Variable	1,042,000/yr
Total	$2,090,000/yr

(B) When burning coal:

Fixed	$1,433,000/yr
Variable	14,452,000/yr
Total	$15,885,000/yr

(iii) *Fuel expense cash flow requirements.*

(A) When burning oil:

First through 24th year	$93,020,000/yr

(B) When burning coal:

First 3 years	$56,033,000/yr
Fourth year through 24th year	$37,355,000/yr

(iv) The plant is assumed to have current book value of $82,988,000 and a remaining tax life of 12 years.

(v) The discount rate for the purpose of this example is 3 percent.

(vi) The powerplant has been operational for 11 years. Its remaining useful life is 24 years.

(vii) It is assumed that no derating is involved.

(9) *Analysis.*[13]

(i) *General cost test.*

(A) Compute the cost of using coal from the start of the exemption.

$$I = \sum_{i=-g}^{N} \frac{I_i - ITC_i - S_i}{(1+K)^i}$$

$$= \frac{49{,}927}{(1.03)^{-1}} + \frac{24{,}963}{(1.03)^{0}}$$

$$- \frac{0.10 \times 74{,}890 \; \text{[14]}}{(1.03)^{1}}$$

$$= 69{,}117$$

$$\text{COST} = I + \sum_{i=1}^{N} \frac{(OH_i + FL_i)(1-t) - t(DPR_i)}{(1+K)^i}$$

$$= 69{,}117 + \sum_{i=1}^{3} \frac{(15{,}885 + 56{,}033)(1-0.46)}{(1.03)^i}$$

$$+ \sum_{i=4}^{24} \frac{(15{,}885 + 37{,}355)(1-0.46)}{(1.03)^i}$$

$$- \sum_{i=1}^{12} \frac{0.46 \times DPR_i \; \text{[15]}}{(1.03)^i} - \sum_{i=1}^{24} \frac{0.46 \times DPR_i \; \text{[16]}}{(1.03)^i}$$

$$= 523{,}349$$

$$\text{COST} = I + \sum_{i=1}^{N} \frac{(OH_i + FL_i)(1-t) - t(DPR_i)}{(1.03)^i}$$

$$= 0 + \sum_{i=1}^{24} \frac{(2{,}090 + 93{,}020)(1-0.46)}{(1.03)^i}$$

$$- \sum_{i=1}^{12} \frac{0.46 \times DPR_i \; \text{[17]}}{(1.03)^i}$$

$$= 838{,}131$$

(C) Compute the ratio of the cost of using coal from the beginning of the exemption to the cost of using oil throughout the remaining useful life of the powerplant.

$$R = \frac{\text{COST (COAL)}}{\text{COST (OIL)}}$$

$$= \frac{523{,}349}{838{,}131}$$

$$= 0.62$$

The ratio is less than 1.3. You are not eligible for either a permanent or temporary exemption using the general cost test and need not complete the general cost test. However, for illustrative purposes, we will continue.

(D) Compute the cost of using coal assuming coal is not used until after the third year and oil is used for the first 3 years of the exemption.

$$I = \sum_{i=-g}^{N} \frac{I_i - ITC_i - S_i}{(1+K)^i}$$

$$= \frac{49{,}927}{(1.03)^{2}} + \frac{24{,}963}{(1.03)^{3}}$$

$$- \frac{0.10 \times 74{,}890 \; \text{[18]}}{(10.3)^{4}}$$

$$I = 63{,}252$$

[13] All dollars are in thousands.

[14] TC is recognized the year the equipment is put into operation.

[15] This term accounts for the depreciation of the original powerplant. Current book value is 82,988 and straight line depreciation is being taken over 12 more years.

[16] This term accounts for the depreciation of the capital investment (pollution control equipment) necessary to burn coal. The depreciation method is the rapid amortization method used for certified pollution control equipment added to a plant in existence before 1976. The tax life is 24 years.

[17] This term accounts for depreciation of the original powerplant. Current book value is 82,988 and straight line depreciation is being taken over 12 more years.

[18] ITC is recognized the year after the plant becomes coal-capable.

$$COST = I + \sum_{i=1}^{N} \frac{(OM_i + FL_i\,(1 - t) - t(DPR_i)}{(1 + K)^i}$$

$$= 63,252$$

$$+ \sum_{i=1}^{3} \frac{(2,090 + 93,020)\;(1 - 0.46)}{(1.03)^i}$$

$$+ \sum_{i=4}^{24} \frac{(15,885 + 37,355)\;(1 - 0.46)}{(1.03)^i}$$

$$- \sum_{i=1}^{12} \frac{0.46 \times DPR_i\ \underline{19}/}{(1.03)^i}$$

$$- \sum_{i=4}^{24} \frac{0.46 \times DPR_i\ \underline{20}/}{(1.03)^i}$$

$$COST = 554,764$$

(E) Compute the ratio of the cost of using coal starting at the end of the third year to the cost of using oil throughout the remaining life of the powerplant.

$$R = \frac{COST(COAL)}{COST(OIL)} = \frac{554,764}{838,131} = 0.66$$

(ii) *Special cost test.*

(A) Compute the cost of using coal assuming the length of the exemption is 3 years.

$$COST = I \times \frac{\sum_{i=1}^{P} (1+K)^{-i}}{\sum_{i=1}^{N} (1+K)^{-i}} + \sum_{i=1}^{P} \frac{(OM_i + FL_i)\quad(1-t) - t(DPR_i)}{(1+K)^i}$$

$$COST = 69,117 \times \frac{\sum_{i=1}^{3} (1.03)^{-i}}{\sum_{i=1}^{24} (1.03)^{-i}}$$

$$+ \sum_{i=1}^{3} \frac{(15,885 + 56,033)\;(1 - 0.46)}{(1.03)^i}$$

$$- \sum_{i=1}^{3} \frac{0.46 \times DPR_i\ \underline{21}/}{(1.03)^i} - \sum_{i=1}^{3} \frac{0.46 \times DPR_i\ \underline{22}/}{(1.03)^i}$$

$$= 97,413$$

$$COST = I \times \frac{\sum_{i=1}^{P} (1+K)^{-i}}{\sum_{i=1}^{N} (1+K)^{-i}} + \sum_{i=1}^{P} \frac{(OM_i + FL_i)\;(1-t) - t(DPR_i)}{(1+K)^i}$$

$$COST = 63,252 \times \frac{\sum_{i=1}^{3} (1.03)^{-i}}{\sum_{i=1}^{24} (1.03)^{-i}}$$

$$+ \sum_{i=1}^{3} \frac{(2090 + 93,020)\;(1 - 0.46)}{(1.03)^i}$$

$$- \sum_{i=1}^{3} \frac{0.46 \times DPR_i\ \underline{23}/}{(1.03)^i}$$

$$= 146,841$$

(C) Compute the ratio of the cost of using coal to the cost of using oil.

$$R = \frac{COST(COAL)}{COST(OIL)} = \frac{97,413}{146,841} = 0.66$$

The ratio (R) is less than 1.3. Therefore, you would not receive a temporary exemption of 3 years. However if the ratio computed where the use of coal is delayed one and two years are higher than 1.3, you would receive a temporary exemption of two years.

§ 504.13 No alternative power supply—general requirement for permanent exemptions.

(a) *Application.* (1) Section 312 of the Act provides for a permanent exemption for State or local requirements and intermediate load. To qualify for one of these exemptions, Section 313(b) requires that you demonstrate to the satisfaction of ERA that despite diligent good faith efforts, there is no alternative supply of electric power which is available within a reasonable distance at a reasonable cost without impairing short-run or long-run reliability of service.

(2) In making the determination as to whether you have satisfied this requirement ERA will consider:

(i) In the case in which a final order has been issued, only the first year in which you propose to use petroleum or natural gas;

(ii) In the case in which you propose to use natural gas in excess of a statutory prohibition, only the first year in which you propose to use the excess natural gas; or

(iii) In the case in which only a proposed order has been issued, only the first year after a date on which the order could reasonably be expected to become effective.

(3) If you are unable to demonstrate that there is no alternate supply during the appropriate period, ERA will conclude that the absence of the existing powerplant will not impair short-term reliability of service, and as a result may deny your exemption. This denial would not impair long-term reliability of service, since you may submit a new petition one year later.

(b) *Criteria.* ERA will determine that you have no alternate supply of power if you demonstrate all of the following:

(1) You have made a diligent effort to reduce the need for power from your existing powerplant by implementing within your system whatever conservation measures are available and cost effective, including increasing the availability of alternate fuel-fired plants and by taking whatever measures are available to you (including, where appropriate, application for waivers from certain prohibitions of the National Energy Conservation Policy Act of 1978) to encourage or assist your customers in implementing cost-effective conservation. In judging whether a conservation measure is cost effective,

[19] This term accounts for the depreciation of the original powerplant. Current book value is 82,988 and straight line depreciation is being taken over 12 more years.

[20] This term accounts for the depreciation of the capital investment (pollution control equipment) required to burn coal. The depreciation method is the rapid amortization method used for certified pollution control equipment added to a plant in existence before 1976. The tax life is 21 years.

[21] This term accounts for the depreciation of the original powerplant. Current book value is 82,988 and straight line depreciation is taken over 12 more years.

[22] This term accounts for the depreciation of the capital investment (pollution control equipment) necessary to burn coal. The depreciation method is the rapid amortization method used for certified pollution control equipment added to a plant in existence before 1976. The tax life is 24 years.

[23] This term accounts for the depreciation of the original powerplant. Current book value is 83,988 and straight line depreciation is taken over 12 more years.

the capacity it would replace should be compared with the life cycle cost of capacity from your existing powerplant including capital operations, and maintenance expenses, and fuel at imported petroleum prices.

(2) You have made a diligent effort to purchase firm power for the appropriate year, described in paragraph (a) of this section, to cover all or part of your projected shortfall at a cost that is less than 10 percent above the annualized adjusted average cost of generating power in your system (including the capital, operation and maintenance expenses, and fuel at imported petroleum prices) for existing oil- or gas-fired units in your system.

(3)(i) Despite these efforts, the reserve margin in your electric region in the absence of your existing plant would fall below 20 percent during the appropriate year described in paragraph (a) of this section; or

(ii) Despite these efforts, the reserve margin will be greater than 20 percent and you have demonstrated that reliability of service would be impaired. Your demonstration relates to factors not included in the calculation of reserve margin such as transmission constraints.

(c) *Evidence.* You must include in your Fuels Decision Report at least the following in order to make the demonstration required by this section:

(1) The estimated peak demand for your system and the coincident peak demand for your electric region for the appropriate year.

(2) The corresponding capacity projections, as well as any existing commitments by your system to purchase or sell power during that year.

(3) Evidence that you have solicited firm power contracts for the appropriate year, via letters to all potential sources (including non-utility sources) within or contiguous to your electric region, and also via advertisements.

(4) A calculation of the delivered cost of the first-purchased power offered in response to you solicitation(s) along with a detailed description of the method by which the annual cost of the purchased power is determined. Where relevant, the FERC Tariff Identifications intended as the basis for the purchase power contracts under negotiation (including the service schedules and/or exhibits which would apply to these contracts) should be provided.

(5) A calculation of the cost of power from your existing powerplant during the appropriate year. You may select the method of calculation, provided that the resulting cost may be meaningfully compared with the cost of purchased power. The calculation must include expenses due to capital, operations and maintenance, and fuel at imported petroleum prices. You may include effects of the economic dispatch of powerplants. The number of kilowatt hours being compared from the existing powerplant and the purchased power should be the same.

(6) A description of the measures you will have taken prior to the appropriate year to reduce energy losses within your own system, to improve the availability of your existing non-oil or gas-fired plants, to shift part of your peak demand to off-peak periods, and to encourage or assist your customers in implementing cost-effective conservation measures.

(7) Estimates of the kilowatt and kilowatt-hour savings that would result from the conservation measures.

(8) A calculation of the net capacity shortfall in the appropriate year (compared to a 20 percent reserve margin) if your existing powerplant is not utilized but all the reasonable purchase and conservation opportunities are exploited.

(d) *FERC consultation.* ERA will forward a copy of any petition for which a showing under this section is required to the Federal Energy Regulatory Commission (FERC) promptly after if is filed with ERA, and ERA will consult with FERC before making a finding on "no alternative supply of power" in the case of a petition for an intermediate or State or local exemption after the issuance of a final prohibition order.

§ 504.14 [Reserved]

§ 504.15 Use of mixtures—general requirement for permanent exemptions.

(a) *Application.* ERA will not consider a petition for any of the following exemptions provided for in Section 312 of the Act (lack of alternate fuel supply, site limitations, environmental requirements, use of natural gas in small powerplants, cogeneration, emergency purposes, or intermediate load) to be complete, adequate, or acceptable for filing unless you demonstrate to the satisfaction of ERA that you have considered the use of a mixture(s) for which an exemption under § 504.36 (Fuel mixtures) of these regulations would be available.

(b) *Demonstration.* ERA will deny any of the exemptions listed above unless you demonstrate that use of such a mixture(s) is not economically or technically feasible in the unit for which you are requesting an exemption. You must submit to ERA at least the following evidence in order to make the demonstration required by this section:

(1) If use of a mixture(s) were required, you would be eligible for one of the following permanent exemptions provided for in the Act: lack of alternate fuel supply. site limitations, environmental requirements, or state or local requirements, or

(2) Use of a mixture(s) is not technically or economically feasible in your specific unit due to design or special circumstances.

§ 504.16 Use of fluidized bed combustion not feasible—general requirement for permanent exemptions.

(a) *ERA finding.* ERA may deny any of the following exemptions provided for in Section 312 of the Act (lack of alternate fuel supply. site limitations, environmental requirements, state or local requirements, cogeneration, emergency purposes, use of natural gas in small powerplants or intermediate load) if ERA finds on a site specific or generic basis that use of a method of fluidized bed combustion of an alternate fuel is economically and technically feasible.

(b) *Demonstration.* If ERA has made such a finding, ERA will deny your request for exemption unless you demonstrate that the use of a method of fluidized bed combustion is not economically or technically feasible. You must include in your Fuels Decisions Report or any supplement thereto required by ERA (or in your petition for an emergency exeption) at least the following evidence:

(1) If use of a method of fluidized bed combustion were required, you would be eligible for one of the following permanent exemptions provided for in Section 312 of the Act: Lack of alternate fuel supply, site limitations, environmental requirements, or state or local requirements; or

(2) Use of a method of fluidized bed combustion is not technically or economically feasible in your specific unit due to design or special circumstances.

§ 504.17 Terms and conditions; compliance plans.

(a) *Terms and conditions generally.* You must comply with the terms and conditions of an exemption granted under the Act by the ERA, including terms and conditions requiring the use of effective fuel conservation measures.

(b) *Compliance plans for temporary exemptions.* (1) A compliance plan certified by your duly authorized representative shall accompany a petition for a temporary exemption. The compliance plan shall include at least the following:

(i) A detailed schedule of progressive events and the dates upon which the events are to take place indicating how compliance with the applicable prohibitions will occur;

(ii) Evidence of binding contracts for fuel, or facilities for the production of fuel, which are required for you to comply with the applicable prohibitions; and

(iii) Any other documentary evidence which indicates an ability to comply with the applicable prohibitions.

(2) The exemption shall not be effective until the compliance plan is approved by ERA.

(3) *Revisions of compliance plans.* If the petition is granted, you must submit to ERA an updated compliance plan certified by your duly authorized representative:

(i) At the end of each 12-month period from the effective date of the exemption;

(ii) Within 1 month of an alteration of any milestones in the compliance plan, together with the reasons for the alteration and its impact upon the scheduling of all other milestones in the plan; and

(iii) At any time the ERA, in its discretion, determines that a revised compliance plan may be necessary to reflect changes in circumstances.

(c) *Enforcement.* An exemption is subject to termination upon the violation of any provision of an exemption or any provision of the pertinent compliance plan.

Subpart D—Temporary Exemptions for Existing Powerplants

§ 504.20 Purpose and scope.

(a) This subpart implements the provisions contained in Section 311 of the Act with regard to temporary exemptions for existing powerplants.

(b) This subpart establishes the criteria and standards which owners or operators of existing powerplants who petition for a temporary exemption must meet to sustain their burden of proof under the Act.

(c) You shall submit all petitions for temporary exemptions for existing powerplants in accordance with the procedures set out in Part 501 of these regulations.

(d) The duration of any temporary exemption granted under this subpart shall be measured from the date that the applicable prohibition would apply if the exemption had not been granted.

§ 504.21 Lack of alternate fuel supply.

(a) *Eligibility.* Section 311(a)(1) of the Act provides for a temporary exemption due to lack of an alternate fuel supply. To qualify you must demonstrate to the satisfaction of ERA that:

(1) You made a good faith effort to obtain an adequate and reliable supply of an alternate fuel of the quality necessary to conform to the design and operational requirements of the existing powerplant;

(2) For the period of the proposed exemption, the cost of using such a supply would substantially exceed the cost of using imported petroleum as a primary energy source as defined in § 504.12 (Cost calculation) of these regulations; and

(3) You will be able to comply with the applicable prohibitions of these regulations at the end of the proposed exemption period.

(b) *Evidence required in support of a petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) A description of your analysis of the alternate fuels you considered for use;

(2) A detailed description of the design requirements you specified for the existing powerplant, including capacity, alternate fuels capability, and all other pertinent specifications;

(3) A description of the range of specific fuel characteristics of all the fuels which can be used by the existing powerplants;

(4) Evidence that you sought to obtain the full range of alternate fuels which could be used by the existing powerplant, including bid requests, and/or advertisements for supply contracts and all responses thereto, as well as any other arrangements you attempted to make to secure supplies;

(5) Evidence of the contracts or other arrangements you have made to ensure a reliable and adequate supply of an alternate fuel at the end of the proposed exemption; and

(6) All data required by § 504.12 (Cost calculation) of these regulations necessary for computing the cost calculation formula.

(c) *Compliance plan.* You must submit to ERA a compliance plan in accordance with Section 314 of the Act and § 504.17 of these regulations simultaneously with submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 504.17 of these regulations and as required by the terms of any order granting an exemption under this subpart.

(d) *Duration.* This temporary exemption, taking into account any extensions or renewals, may not exceed ten years.

§ 504.22 Site limitations.

(a) *Eligibility.* Section 311(a)(2) of the Act provides for a temporary exemption due to a site limitation. To qualify for such an exemption, you must demonstrate that one or more of the following specific physical limitations relevant to the location or operation of your powerplant exist which, despite your diligent good faith efforts, cannot be overcome before the end of the proposed exemption period:

(1) Alternate fuels would be inaccessible because of a specific physical limitation;

(2) Transportation facilities for alternate fuels would be unavailable;

(3) Adequate land or facilities for handling, using or storing an alternate fuel would be unavailable;

(4) Adequate means for controlling and disposing of wastes would be unavailable;

(5) Adequate and reliable supply of water would be unavailable; or

(6) Other site limitations exist which would not permit the operation of the existing powerplant using an alternate fuel.

(b) *Evidence required in support of a petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) Evidence that the site limitation is a physical limitation, and not a requirement of Federal, State, or local law which could be the basis of an exemption under § 501.34 (State or local requirements);

(2) Evidence that alternative means for overcoming the specific site limitations were considered, with a detailed description of the efforts made to overcome the site limitations set out in your petition;

(3) Evidence of the equipment or space requirements for which the site limitation is claimed; and

(4) Evidence of contracts or other arrangements you have made to insure that the site limitation will overcome and that you will comply with the applicable prohibitions at the end of the proposed exemption period. Examples of evidence relevant to establishing a site limitation for purposes of a temporary exemption are as follows:

(i) Detailed documentation of impediments, including rights of way problems, site diagrams, maps of the surrounding areas and other items essential to the showing of a site limitation;

(ii) Identification of transportation facilities relevant to the specific site of the powerplant and demonstration why existing transportation facilities cannot be utilized or new facilities constructed;

(iii) Copies of bid requests, advertisements, and general efforts made to secure alternative transportation facilities;

(iv) Identification of potential alternate fuel storage locations within a reasonable geographic area surrounding the powerplant;

(v) Detailed scale site plans of the entire facility which include those areas not directly involved with the specific boiler;

(vi) A specific listing of all equipment necessary and not currently available to properly handle alternate fuel;

(vii) Copies of bid requests, advertisements and general efforts made to secure alternative fuel storage facilities;

(viii) Copies of quotes from bona fide suppliers, indicating lead times for purchase and installation of required ancillary storage of handling equipment;

(ix) Specific listing of any equipment necessary and not currently available to properly control and dispose of waste;

(x) Identification of potential alternate waste disposal locations within a reasonable geographic area surrounding the powerplant;

(xi) A description of efforts made to secure off site disposal areas, including the cost of acquisition of the sites, transportation facilities and waste handling costs involved in their use; and

(xii) Copies of bid requests, advertisments, and general efforts made to secure control and disposal equipment.

(c) *Compliance plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 504.17 of these regulations simultaneously with submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 504.17 of these regulations and as may be required by the terms of any order granting an exemption under this subpart.

(d) *Duration.* This temporary exemption, taking into account any extensions or renewals, may not exceed five years.

§ 504.23 Inability to comply with applicable environmental requirements.

(a) *Eligibility.* Section 311(a)(3) of the Act provides for a temporary exemption due to an inability to comply with applicable environmental requirements. To qualify you must demonstrate to the satisfaction of ERA that despite diligent good faith efforts:

(1) You are unable to comply with the applicable prohibitions without violating applicable Federal or State environmental requirements; and

(2) You will be able to comply with the applicable prohibitions imposed by the Act and with applicable environmental requirements by the end of the temporary exemption period.

(b) *Criteria.* ERA's decision with regard to environmental compliance will be based solely on analysis of your capacity to physically achieve applicable environmental requirements. You should direct your analysis toward those conditions or circumstances which make it physically impossible for you to comply with applicable environmental requirements during the temporary exemption period. The cost of compliance shall not enter into the analysis, but any cost related considerations may be presented as part of a demonstration submitted under § 504.21.

(c) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) An examination of the environmental compliance of the facility, including an analysis of the ability to meet applicable standards and criteria when using both the proposed fuel and all alternate fuels with reference to which you are requesting an environmental exemption. All conclusions regarding the ability of the facility to comply must be based on accepted analytical techniques, such as air quality modeling, and must reflect current conditions of the area which would be affected by the facility. You are responsible for performing the necessary sampling and collecting sufficient data to accurately characterize these conditions. Environmental compliance must be examined in the context of the available pollution control equipment which would provide the maximum possible reduction of pollution. The analysis must contain requests for bids and other inquiries made and responses received by you concerning the availability and performance of pollution control equipment; contracts signed, if any, for an alternate fuel supply and for the purchase and installation of pollution control equipment; or other comparable evidence such as technical studies documenting efficacy of equipment to meet applicable requirements; and

(2) An examination of the regulatory options available to you in seeking to achieve environmental compliance. This must include an analysis of the availability of offsets, if needed, and the potential for securing variances, and State Implementation Plan revisions, as appropriate. The analysis must illustrate and document your efforts, if any, to locate, identify, and acquire offsets, including agreements made by agreement to acquire offsets is conditioned upon the grant of a variance, or State Implementation Plan revision, you must submit a letter from the state agency indicating when a proceeding to effectuate the agreement will take place. The analysis must contain any correspondence initiated or received by you concerning these regulatory options and all technical studies you have relied upon to support your conclusions. In addition you may submit any other documentation you believe demonstrates an inability to comply with applicable environmental requirements despite good faith efforts.

(d) *Compliance plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 504.17 of these regulations simultaneously with the submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 504.17 of these regulations and as required by the terms of any order granting an exemption under this subpart.

(e) *Other action.* Prior to deciding to submit an exemption application, it is recommended that you request a meeting with ERA and EPA or the appropriate state or local regulatory agency to discuss options for operating an alternate fuel-fired facility in compliance with applicable environmental requirements.

(f) *Duration.* This temporary exemption, taking into account extensions and renewals, may not exceed 5 years, and will be issued by ERA for such period up to and including 5 years as the petition demonstrates is necessary.

§ 504.24 Future use of synthetic fuels.

(a) *Eligibility.* Section 311(b) of the Act provides for a temporary exemption based upon the future use of synthetic fuels. To qualify, you must demonstrate to the satisfaction of ERA that:

(1) You will be able to comply with the applicable prohibitions by the use of synthetic fuel derived from coal or another alternate fuel as a primary energy source in your powerplant by the end of the proposed exemption period;

(2) You will not be able to comply with the applicable prohibitions before the end of the proposed exemption period by using such synthetic fuel in your powerplant.

(b) *Evidence required in support of the petition.* You must include in your

Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) Copies of studies relating to the economic and technical feasibility of using synthetic fuels by your powerplant;

(2) Evidence of the financial commitments you have made to construct, operate, and maintain equipment which will be capable of using synthetic fuel as the primary energy source at the end of the proposed exemption period;

(3) Copies of bid requests, advertisments, contracts and/or other agreements relating to the production, purchase, and transportation of synthetic fuel; and

(4) Information regarding any permits that may be required by Federal or State agencies for the construction and operation of a powerplant using synthetic fuels.

(c) *Compliance plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 504.17 of these regulations simultaneously with submission of your petition. You shall submit an updated compliance plan, if applicable, as may be required by § 504.17 of these regulations and as required by the terms of any order granting an exemption under this subpart.

(d) *Duration.* This temporary exemption may be granted for a period of up to five years and may be extended for up to an additional five years.

§ 504.25 Use of innovative technologies.

(a) *Eligibility.* Section 311(c) of the Act provides for a temporary exemption based upon the use of innovative technologies. To qualify you must demonstrate to the satisfaction of ERA that you will be able to comply with the applicable rule or order at the end of the proposed exemption period by adoption of a technology for the use of an alternate fuel which ERA determines to be an innovative technology.

(b) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) Copies of economic and technical feasibility studies pertaining to adoption of an innovative technology for use of an alternate fuel in your installation;

(2) A complete description of the innovative technology you propose to use including explanation of its innovative characteristics, detailed design and engineering specifications, and a description of the fuel characteristic of the alternate fuels which can be used with the innovative technology.

(3) Reliable evidence of the financial and contractual commitments you have made to construct or modify, operate, and maintain equipment which represents and innovative technology for the use of alternate fuel and which will be used at the end of the proposed exemption period; and

(4) Copies of bid requests, advertisement contracts, and/or other arragements you have made to insure a reliable and adequate supply of an alternate fuel at the end of the proposed exemption period.

(c) *Compliance plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 504.17 of these regulations simultaneously with submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 504.17 of these regulations and as may be required by the terms and conditions of any order granting an exemption under this subpart.

(d) *Other action.* Prior to deciding to submit an exemption application, it is recommended that you request a pre-petition conference with ERA to discuss the requirements of this exemption.

(e) *Duration.* This temporary exemption may be granted for a period of up to 5 years and may be extended for an additional 5 years, but so extended may not exceed 10 years.

§ 504.26 Public interest exemption.

(a) *Policy note.* The use of coal and other alternate fuels in lieu of petroleum and natural gas is in the public interest. ERA will grant this temporary exemption where you are unable to comply immediately with the prohibitions of the Act or order by ERA where the granting of the petition would be in the public interest, and where you will be in compliance with the prohibitions imposed by the Act at the end of the exemption period. In filing your petition, you are required to complete the portions of the Fuels Decision Report (FDR) specified in section 502 of these Interim Rules and demonstrate why your proposed facility could not burn a fuel mixture during the time the exemption is effective. ERA recognizes, however, that there are situations where the public interest would best be served by not requiring the FDR and mixture demonstration; consequently, ERA strongly urges you to request a prepetition conference where, after consideration of the facts of your case, ERA could waive all or part of these requirements.

(b) *Eligibility.* Section 311(e) of the Act provides for a temporary public interest exemption. To qualify, you must demonstrate to the satisfaction of ERA that:

(1) You are unable to comply with the applicable prohibitions imposed by the Act, because of extraordinary circumstances, during the period for which the exemption is requested, but that you will be capable of complying at the end of the proposed exemption period; and

(2) The granting of the petition would be in accordance with the purposes of the Act and would be in the public interest.

(c) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) Substantial evidence to corroborate the eligibility requirements identified above:

(2) A demonstration that the use of a mixture, for which an exemption under § 504.36 (Fuel Mixtures) would be available, is not technically or economically feasible during the period the temporary public interest exemption is in effect; and

(3) Information and data required by § 502.4 (Introduction), § 502.7 (Evidence for Exemption Required), and § 502.12 (Conservation Measures) of the Fuels Decision Report as set out in Part 502.

(d) *Compliance plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 504.17 of these regulations simultaneously with submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 504.17 of these regulations and as may be required by the terms of any order granting an exemption under this subpart.

(e) *Duration.* This temporary exemption, taking into account extension and renewals, may not exceed 5 years.

§ 504.27 Retirement.

(a) *Eligibility.* Section 311(d) of the Act provides for a temporary exemption for retirement. To qualify, you must demonstrate to the satisfaction of ERA that the powerplant will be retired at or before the expiration of this temporary exemption. Retirement means for purposes of this exemption that the unit permanently ceases operation.

(b) *Evidence required in support of the petition.* You must include in your petition at least the following evidence in order to make the demonstration required by this section:

(1) Copies of FPC form #12 including Schedules A & B, filed by the operating utility during the previous two years;

(2) Copies of reports filed by the operating utility during the two years preceding the petition with its Reliability Council detailing 10 year projections of changes in generating capacity. (These reports are required by FPC Form #383-4.);

(3) Any state PUC permits necessary for the retirement of a powerplant and a copy of the notification to the state PUC of retirement, if any; and

(4) Any other documentary evidence which indicates the reasons for retirement and plans for replacement or substitution of the retired powerplant.

(c) *Compliance plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 504.17 of these regulations simultaneously with submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 504.17 (except § 504.17(b)(1)(ii) of these regulations and as may be required by the terms of any order granting an exemption under this subpart.

(d) *Duration.* This temporary exemption, taking into account extensions or renewals, may not exceed 5 years.

(e) *Restriction.* In the event this exemption is granted you will not be eligible for any other exemption under Title III, Subtitle B of the Act.

§ 504.28 Temporary exemption for powerplants necessary to maintain reliability of service.

(a) *Eligibility:*

(1) Section 311(g) of the Act provides for a temporary exemption to maintain reliability of service. To qualify you must demonstrate to the satisfaction of ERA that you are not capable of complying with the applicable prohibitions imposed by the Act without an impairment of reliability of service as measured by the loss of load probability technique described in paragraphs (a)(2) and (a)(3) of this section.

(2) You must calculate reliability of service utilizing the loss of load probability (LOLP) technique. The LOLP must be computed for your electrical region using the first 12-month period beginning on the first day of the month following the effective date of the exemption. It is to be calculated as the sum of either the weekly or the monthly estimates of hourly load/capacity deficits. You may decide whether to perform the calculation using weekly or monthly data. The LOLP calculation must take into consideration equipment forced outage rates, projected customer electrical demand, and generating capacity projections for the electrical region, including existing generating capacity, planned generating capacity additions and projected firm bulk electrical purchases and sales, and projected retirements. If necessary, you may also calculate LOLP with modifications to account for transmission constraints, energy shortages, and other factors that are not adequately addressed by adhering to the foregoing specifications. You will need to discuss why such modifications are appropriate.

(3) Reliability of service will be considered impaired if the LOLP during the 12-month period described in paragraph (a)(2) of this section, including all available emergency reliability connections and other bulk power ties, is greater than one day in 5 years.

(4) You may choose to argue that your case for impaired reliability is supportable by criteria other than in paragraph (a)(2) of this section. If so, you must present this argument, and propose an approach for its justification, in a prepetition conference for ERA concurrence.

(b) *Evidence supporting the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) All data you used in determining the loss of load probability;

(2) An explanation including equations of how you are calculating the loss of load probability;

(3) A description of your method and assumptions for projecting demand for your system and for your electric region;

(4) Your strategy for ending your period of reliability impairment, describing the measures you expect to take to reduce your demand and/or to increase your supply of power from sources other than your proposed plant that are either alternate fuel-fired or qualify for other exemptions;

(5) A calculation of your expected date of termination for your period of impairment. You may specify several alternate termination dates, each corresponding to a different combination of major events that are beyond your control (such as slippages of a new plant being built by a different utility in your electric region);

(6) In addition, you may include other evidence that you believe is relevant to your case, such as:

(i) Evidence that the reliability advantages of coordination on an electric region basis cannot be achieved to an extent sufficient to remove your "impairment of reliability", reasons for this deficiency, and an estimate of when such coordination could be implemented in your region; or

(ii) Evidence that your system has a unique situation that requires the use of different reliability criteria.

(c) *Additional information.* You must submit the following information:

(1) All data required by § 502.11 (Petroleum and natural gas use) of these regulations; and

(2) All data required by § 502.12 (Conservation measures) of these regulations which describe any oil and natural gas conservation measures you have taken or intend to take if the exemption is granted.

(d) *Terms and conditions.* If you obtain this temporary exemption, you will be permitted to operate your powerplant only for the purposes of preventing an impairment of reliability of service. Your exemption period will extend from the effective date of the exemption until the earliest date when you can reduce your LOLP to less than 1 day in 5 years by means of measures which are in compliance with the prohibitions in the Act. ERA, at the time it grants this exemption, will specify the expected termination date of your exemption period. If circumstances beyond your control, which could not reasonably be anticipated at the time your petition was filed, cause the LOLP of your electric region to exceed 1 day in 5 years either at the end of this period or at any subsequent time, you may continue operation or recommence operation. You must supply detailed LOLP calculations to support the continuation or recommencement of operation.

(e) *Foreclosure of other exemptions.* Notwithstanding any other provision of these regulations or of the Act, an exemption under this Part (other than a permanent exemption under § 504.38 for the use of petroleum) may not be granted for any powerplant for which an exemption under this section has been granted.

(f) *Compliance plans.* You must submit to ERA a compliance plan in accordance with Section 314 of the Act and § 504.17 of these regulations simultaneously with submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 504.17 of these regulations and as may be required by the terms of any order granting an exemption under this subpart.

(g) *Duration.* This temporary exemption, taking into account extensions or renewals, may not exceed 5 years or in the case of natural gas extend beyond December 31, 1994 whichever comes first.

§ 504.29 Peakload powerplants.

(a) *Eligibility.* (1) If you propose to use natural gas or petroleum as a primary energy source in an existing peakload powerplant Section 311(f) of the act provides for a temporary exemption for peakload powerplants. To qualify you must certify to ERA that the powerplant will be operated solely as a peakload powerplant and to meet peakload demand for the period of the exemption.

(b) *Evidence required in support of a petition.* You must include in your petition at least the following evidence in order to make the demonstration required by this section:

(1) The petition must be accompanied by a sworn statement signed by a duly authorized officer of the electric utility which will operate the powerplant certifying that the powerplant is to be operated solely as a peakload powerplant and to meet peakload demand for the period of the exemption. The certification must set forth the design capacity of the powerplant and the maximum allowable generation of the powerplant in kilowatt hours according to the definition of peakload for each 12 month period of operation as a peakload powerplant. The first such period shall begin on the first day of the month following the effective date of the exemption.

(2) *Compliance plan.* You must submit to ERA a compliance plan in accordance with Section 314 of the Act and § 504.17 of these regulations simultaneously with submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 504.17 of these regulations and as required by the terms of any order granting an exemption under this subpart.

(c) *Additional information.* You must submit the following additional information:

(1) All data required by § 502.11 (Petroleum and natural gas use) of these regulations; and

(2) All data required by § 502.12 (Conservtion measures) of these regulations which describe any oil or natural gas conservation measures you have taken or intend to take if the exemption is granted.

(d) *Liability for operating in excess of exemption.* The operation of a peakload powerplant which has been granted this exemption in excess of that allowed by the exemption shall be subject to penalties under Title VII, Subtitle C of the Act unless the powerplant meets the criteria set forth in Section 721(c) of the Act.

(e) *Duration.* This temporary exemption, taking into account extensions or renewals, may not exceed 5 years or in the case of natural gas extend beyond December 31, 1994, whichever comes first.

(f) *Reporting requirements.* If the petition is granted you must report to ERA, at the end of each 12-month period of the proposed exemption. The first such period shall begin on the first day of the month following the effective date of the exemption. If applicable, upon reaching the maximum number of kilowatt hours of permitted generation within the 12-month period, you must report the name, location, and design capacity of the exempted unit, the number of hours of operation permitted by the exemption, and the number of hours of actual operation.

Subpart E—Permanent Exemptions for Existing Powerplants

§ 504.30 Purpose and scope.

(a) This subpart implements the provisions contained in Section 312 of the Act with regard to permanent exemptions for existing electric powerplants.

(b) This subpart establishes the criteria and standards which owners or operators of existing powerplants that petition for a permanent exemption must meet to sustain their burden of proof under the Act.

(c) If a petition for a permanent exemption is filed pursuant to § 504.31 (Lack of alternate fuel supply); § 504.32 (Site limitation); § 504.33 (Inability to comply with applicable environmental requirements); or § 504.34 (State or local requirements); the petitioner must demonstrate that his inability to use each reasonable alternate fuel would entitle him to one or more of the above exemptions.

(d) You must submit all petitions for permanent exemptions for existing powerplants in accordance with the procedures set out in Part 501 of these regulations.

§ 504.31 Lack of alternate fuel supply.

(a) *Eligibility.* Section 312(a)(1)(A) of the Act provides for a permanent exemption due to lack of an alternate fuel supply at a cost which does not substantially exceed the cost of using imported petroleum. To qualify you must demonstrate to the satisfaction of ERA that:

(1) You made a good faith effort to obtain an adequate and reliable supply of an alternate fuel of the quality necessary to conform with the design and operational requirements of the existing powerplant; and

(2) The cost of using such a supply would substantially exceed the cost of using imported petroleum as a primary energy source during the remaining useful life of the existing powerplant as defined in § 504.12 (Cost calculation) of these regulations.

(b) *Evidence in support of a petition.* You must include in your Fuels Decision Report the following evidence in order to make the demonstration required by this section:

(1) A detailed description of the design requirements you specified for the existing powerplant, including capacity, alternate fuels capability, and all other pertinent specifications;

(2) A description of the range of specific fuel characteristics of all the fuels which can be used by the existing powerplant;

(3) Evidence that you sought to obtain the full range of alternate fuels and fuel characteristics which could be used by the existing powerplant, including bid requests and/or advertisements for supply contracts, all proposals and responses thereto, as well as any other arrangements you attempted to make to secure supplies.

(4) All data required by § 504.12 of these regulations (Cost calculation) necessary for computing the cost calculation formula; and

(5) A description of your analysis of the alternate fuels you considered.

§ 504.32 Site limitations.

(a) *Eligibility.* Section 312(a)(1)(B) of the Act provides for a permanent exemption due to a site limitation. To qualify for such an exemption you must demonstrate that, despite good faith efforts:

(1) Alternate fuels are inaccessible as a result of a specific physical limitation to the operation of the existing powerplant;

(2) Transportation facilities for alternate fuels would be unavailable;

(3) Adequate land or facilities for handling, using or storing alternate fuels would be unavailable;

(4) Adequate means for controlling and disposing of wastes would be unavailable;

(5) Adequate and reliable supply of water would be unavailable; or

(6) Other site limitations exist which would not permit the operation of the existing powerplant using an alternate fuel, and these limitations cannot be reasonably expected to be overcome within five years after the effective date of the applicable prohibition.

(b) *Evidence to be submitted in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) Evidence that the site limitation is a physical limitation, and not a requirement of Federal, State or local law which could be the basis of an exemption under § 504.34 (State or local requirements);

(2) Evidence that alternative means for overcoming the specific site limitations were considered with a detailed description of the efforts made to overcome the site limitations set out in your petition; and

(3) Evidence of the equipment or space requirements for which the site limitation is claimed. Examples of evidence relevant to establishing a site limitation for purposes of a permanent exemption are as follows:

(i) Detailed demonstration of impediments, including rights of way problems, site diagrams, maps of the surrounding areas and other items essential to the showing of a site limitation;

(ii) Identification of transportation facilities relevant to the geographic site of the powerplant and demonstration why existing transportation facilities cannot be utilized or new facilities constructed;

(iii) Identification of potential alternate waste disposal locations within a reasonable geographic area surrounding the powerplant;

(iv) A description of efforts made to secure off-site disposal area, including the cost of acquisition of the sites, transportation facilities and waste handling costs involved in their use;

(v) Copies of bid requests, advertisements, and other general efforts made to secure waste control and disposal equipment;

(vi) Copies of bid requests, advertisements, and other general efforts made to secure alternative fuel storage facilities;

(vii) Identification of potential alternate fuel storage locations within a reasonable geographic area surrounding the powerplant;

(viii) Detailed scale site plans of the entire facility which include those areas not directly involved with the specific powerplant;

(ix) A specific listing of all equipment necessary and not currently available to properly handle alternate fuels;

(x) Copies of quotes from bona fide suppliers, indicating lead times for purchase and installation of required ancillary storage or handling equipment;

(xi) Specific listing of any equipment necessary and not currently available to properly control and dispose of waste.

§ 504.33 Inability to comply with applicable environmental requirements.

(a) *Eligibility.* Section 312(a)(1)(C) of the Act provides for a permanent exemption due to the inability to comply with the applicable environmental requirements. To qualify you must demonstrate to the satisfaction of ERA that, despite good faith efforts you will be unable, within 5 years of the date the exemption is requested to take effect, to comply with the applicable Federal or state environmental requirements.

(b) *Criteria.* ERA's decision with regard to environmental compliance will be based solely on an analysis of your capacity to physically achieve applicable environmental requirements. The cost of compliance shall not enter into the analysis, but any cost-related considerations may be presented as part of a demonstration submitted under § 504.31.

(c) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) An examination of the environmental compliance of the facility, including an analysis of the ability to meet applicable standards and criteria when using both the proposed fuel and all alternate fuels for which you are requesting an environmental exemption. All conclusions regarding the ability of the facility to comply must be based on accepted analytical techniques, such as air quality modeling, and must reflect current conditions of the area which would be affected by the facility. You are responsible for performing the necessary sampling and collecting sufficient data to accurately characterize these conditions. Environmental compliance must be examined in the context of the available pollution control equipment which would provide the maximum possible reduction of pollution. The analysis must contain requests for bids and other inquiries made and responses received by you concerning the availability and performance of pollution control equipment, or other comparable evidence such as technical studies documenting efficacy of equipment to meet applicable requirements; and

(2) An examination of the regulatory options available to you in seeking to achieve environmental compliance. This must include an analysis of the availability of offsets, if needed, and the potential for securing variances and State Implementation Plan (SIP) revisions, as appropriate. The analysis must illustrate and document your efforts, if any, to locate and identify available offsets, and to secure variances and SIP revisions. The analysis must contain any correspondence initiated or received by you concerning these regulatory options and all technical studies you have relied upon to support your conclusions.

(3) In addition, you may submit any other documentation you believe demonstrates an inability to comply with applicable environmental requirements despite good faith efforts.

(d) *Other actions.* Prior to deciding to submit an exemption application, it is recommended that you request a meeting with ERA and EPA or the appropriate state or local regulatory agency to discuss options for operating an alternate fuel-fired facility in compliance with the applicable environmental requirements.

§ 504.34 State or local requirements.

(a) *Eligibility.* Section 312(b) of the Act provides for an exemption due to state or local requirements. To qualify you must demonstrate to the satisfaction of ERA that:

(1) With respect to the site of the powerplant, the operation of such powerplant using an alternate fuel is not feasible because of a state or local requirement;

(2) If such state or local requirement is under a building code or nuisance or zoning law, no other exemption could be granted for such facility;

(3) You have in good faith attempted unsuccessfully to obtain a variance from the state or local requirement or have demonstrated why none is available;

(4) The granting of the exemption would be in the public interest and would be consistent with the purposes of this Act;

(b) *Evidence required in support of a petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) A copy of the pertinent state or local requirement with its citation and its legislative history;

(2) The identification and location of the administrative body which implements the requirement;

(3) A description of your attempts to obtain a variance from the requirement or a demonstration of why none is available;

(4) A description of any activities you were involved in after April 20, 1977, pertaining to the enactment of the requirement;

(5) A description of equipment, procedures, and the advance planning time necessary to comply with the requirement;

(6) A detailed description of why compliance with the state or local requirement is infeasible;

(7) The impact upon you and/or your local community, if any, should your petition be denied;

(8) An explanation of the reasons why granting this exemption would be in the public interest; and

(9) An analysis of why you cannot qualify for any other exemption, if the state or local requirement is under a building code or nuisance or zoning law.

(c) *Exercise of discretion by ERA.* ERA may refuse to grant this exemption to you if it determines that such grant would not be in the public interest or in accordance with the purposes of the Act, notwithstanding the fact that the evidence you have furnished to ERA in your exemption petition substantiates that your facility would otherwise be eligible to receive the exemption.

§ 504.35 Cogeneration.

(a) *Eligibility.* Section 312(c) of the Act provides for a permanent exemption for cogeneration. To qualify you must show that economic and other benefits of cogeneration are unobtainable unless petroleum or natural gas, or both are used by demonstrating to the satisfaction of ERA at least the following minimum criteria:

(1) The oil or gas to be consumed by the cogeneration facility will be less than that which would otherwise be consumed in the absence of the cogeneration facility where the calculation of savings is in accordance with paragraph (c) of this section; or

(2) It would be in the public interest to grant an exemption to the cogeneration facility because of special circumstances such as technical innovation or maintaining industry in urban areas.

(b) *Specifications of the cogeneration facility.* (1) A person operating a cogeneration facility may apply for an exemption under this section if the amount of net electricity that is either sold or exchanged is 50 percent or more of the useful energy output of the facility. If the amount is less than 50 percent, see § 505.27 (Installations). Net electricity excludes sales or exchanges among owners of the cogeneration facility.

(2) Electricity generated by the cogeneration facility must constitute more than 10 percent of the useful energy output of the facility and less than 90 percent of the useful energy output.

(c) *Calculation of oil and gas savings.* There is an oil and gas savings if the oil or gas to be consumed by the cogeneration facility will be less than that which would otherwise be consumed in the absence of the cogeneration facility. The calculation of the oil and gas which would otherwise be consumed must be in accordance with paragraphs (c)(1) and (2) of this section.

(1) Except for the case described in paragraph (c)(2) of this section, the oil or gas which would otherwise be consumed must be calculated as follows:

(i) You may include the oil or gas that would be consumed by facilities that are or would be too small to be covered by the FUA regulations. In the case of new small industrial units, you must demonstrate that it would be reasonable to construct units of that size.

(ii) You may include the oil or gas that would be consumed by units in place (existing or exempt) covered by FUA if they are less than 40 years old in the case of a field-erected unit or less than 20 years old in the case of a packaged unit. In the case of existing units, you may not include units that have burned an alternate fuel or are capable of burning an alternate fuel, and you may only include units described in this paragraph if they will be retired if this exemption is granted.

(iii) You may include the oil or gas that would be consumed by units not yet constructed that would be covered by the FUA regulations if you can demonstrate that each unit would be entitled to an exemption.

(iv) You may include the oil or gas that would be consumed by powerplants to generate electricity supplied to the grid to the extent that such electricity, if you cogenerate, will no longer be supplied by the grid. The oil or gas portion must be based on a 10 year forecast that includes new construction and retirement of plants within those 10 years.

(2) In the case of a cogeneration facility that would consist of an existing unit and a new unit, you must calculate the amount of oil or gas that would otherwise be consumed as the sum of:

(i) The five-year average oil or gas consumption of the existing unit, and

(ii) The amount that would be consumed in units described in paragraph (c)(1) (i)–(iv), of this section that would now be satisfied by the new cogeneration facility.

(d) *Evidence required in support of a petition.* You must include in your Fuel Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) An engineering description of the cogeneration system, including proposed output and uses thereof, with sufficient detail to ensure that the facility qualifies as a cogeneration facility;

(2) A detailed oil and natural gas savings calculation identifying the projected oil or natural gas consumption of the cogeneration facility and the oil or natural gas that would otherwise be used;

(3) Identification of the FUA status of the units described in paragraph (c)(1)(i)–(iv) of this section with respect to coverage and designation as new, existing, or exempted, age of units, and alternate fuel capability of units;

(4) Identification of all persons and their roles in the proposed cogeneration facility;

(5) In the case of paragraph (a)(2) of this section, an explanation of the public interest factors you believe should be considered by ERA.

(e) *Exercise of discretion by ERA.* ERA may refuse to grant this exemption to you if it determines that such grant would not be in the public interest or in accordance with the purposes of the Act, notwithstanding the fact that the evidence you have furnished to ERA in your exemption petition substantiates that your facility would otherwise be eligible to receive the exemption.

§ 504.36 Permanent exemption for certain fuel mixtures containing natural gas or petroleum.

(a) *Eligibility.* Section 312(d) of the Act provides for a permanent exemption for certain fuel mixtures. To qualify you must demonstrate to the satisfaction of ERA that:

(1) You propose to use a mixture of natural gas or petroleum and an alternate fuel as a primary energy source;

(2) The amount of petroleum or natural gas you propose to use in the mixture will not exceed the minimum percentage of the total Btu heat input needed to maintain operational reliability of the powerplant consistent with maintaining a reasonable level of fuel efficiency.

(b) *Evidence required in support of a petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) A complete description of the fuel mixture, component elements of the mixture, and percentage of each component to be utilized;

(2) Your design specifications for the unit for which you are requesting an exemption; and

(3) An engineering assessment of the proportions of petroleum or natural gas needed to maintain operational reliability and an adequate level of fuel efficiency.

(c) *Reporting requirement.* If the exemption is granted, you must submit an annual report to ERA certifying that the affected units have used no more than the percentage of oil or natural gas specified in the exemption order. The certification shall be executed by your duly authorized representative.

(d) *Solar mixtures.* ERA will grant a permanent mixtures exemption for the use of a mixture of solar energy (including wind, tide, and other intermittent sources) and petroleum or natural gas, where:

(1) Solar energy will account for at least 20 percent of the total annual Btu heat input of the unit; and

(2) You propose an acceptable plan to ERA which—

(i) Meets the evidence requirements set forth in paragraph (b) of this section; and

(ii) Contains a compliance plan prepared in accordance with § 504.17 of these regulations.

§ 504.37 Emergency purposes.

(a) *Eligibility.* Section 312(e) of the Act provides for a permanent exemption for emergency purposes. To qualify you must demonstrate to the satisfaction of ERA that you will operate and maintain the powerplant for emergency purposes only.

(b) *Definition.* For the purposes of this permanent exemption an emergency exists when the operating utility would be required to curtail noninterruptible electric supply to its industrial customers.

(c) *Evidence required in support of a petition.* You must include in your petition the following evidence in order to make the demonstration required by this section:

(1) A certificate executed by a duly authorized officer of the operating utility stating that emergency operation under the provisions of this exemption will occur only when the noninterruptible electric supply to industrial customers would be curtailed;

(2) All data required by § 504.15 (Use of mixtures—general requirement) of these regulations demonstrating that use of a mixture(s) is not economically or technically feasible; and

(3) All data required by § 504.16 (Use of fluidized bed combustion not feasible—general requirement) if ERA has made a generic or site-specific finding that the use of a method of fluidized bed combustion of an alternate fuel is economically and technically feasible.

(d) *Additional information.* You must submit the following additional information:

(1) All data required by § 502.11 (Petroleum and natural gas use) of these regulations;

(2) All data required by § 502.12 (Conservation measures) of these regulations which describe any oil or natural gas conservation measures you have taken or intend to take if the exemption is granted; and

(3) All data required by § 502.13 (Environmental impacts analysis) of these regulations which will assist ERA to fulfill its responsibilities under the National Environmental Policy Act (NEPA).

(e) *Reporting requirement.* At the end of each 12-month period from the effective date of the exemption, you must report to ERA the monthly and annual amounts of electricity generated and fuel used under the provisions of this exemption with a description of the purposes of use.

§ 504.38 Peakload powerplants.

(a) *Eligibility.* (1) Section 312(f) of the Act provides for a permanent exemption for peakload powerplants if you propose to use petroleum or natural gas as a primary energy source in a peakload powerplant. To qualify:

(i) You must certify to ERA that the powerplant will be operated solely as a peakload powerplant and to meet peakload demand for the remaining life of the powerplant; and

(ii) A denial of such petition is likely to result in an impairment of reliability of service as measured by the loss of load probability technique described in paragraphs (a)(3), and (a)(4) of this section; and

(iii) Modification of the powerplant to permit compliance with the prohibitions of the Act—

(A) Is technically infeasible; or

(B) Would result in an unreasonable expense.

(2) You must calculate reliability of service utilizing the loss of load probability (LOLP) technique. The LOLP must be computed for your electrical region using the first 12-month period of the proposed exemption beginning on the first day of the month following the effective date of the exemption. It is to be calculated as the sum of either the weekly or the monthly estimates of hourly load/capacity deficits. You may decide whether to perform the calculation using weekly or monthly data. The LOLP calculation must take into consideration equipment forced outage rates, projected customer electrical demand, and generating capacity projections for the electrical region, including existing generating capacity, planned generating capacity additions and projected firm bulk electrical purchases and sales, and projected retirements. If necessary, you may also calculate LOLP with modifications to account for transmission restraints, energy shortages, and other factors that are not adequately addressed by adhering to the foregoing specifications. You will need to discuss why such modifications are appropriate.

(3) Reliability of service will be considered impaired if the LOLP for the 12-month period is greater than one day in five years.

(4) You may choose to argue that your case for impaired reliability is supportable by criteria other than in paragraph (a)(2) of this section. If so, you must present this argument, and propose an approach for its justification, in a prepetition conference for ERA concurrence.

(5) *Technical infeasibility.* ERA will consider compliance with the applicable prohibitions of FUA to be technically infeasible if the facility is not "technically capable" of burning an alternative fuel, and if it is not true that the facility "has or previously had the technical capability" to use an alternate fuel pursuant to § 500.1(b)(1) of these regulations.

(b) *Evidence required in support of a petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) A sworn statement signed by a duly authorized officer of the electric utility which will operate the powerplant certifying that the powerplant is to be operated solely as a peakload powerplant and to meet peakload demand for the life of the plant. The certification must set forth the design capacity of the powerplant and the maximum allowable generation of the powerplant in kilowatt hours according to the definition of peakload for each 12 months of operation as a peakload powerplant, and that the powerplant is to be operated solely to meet peakload demand for the remaining life of the powerplant.

(2) All data you used in determining the loss of load probability;

(3) An explanation, including equations, of how you are calculating the loss of load probability;

(4) A description of your method and assumptions for projecting demand for your system and for your electric region;

(5) Your strategy for ending your period of reliability impairment; describing the measures you expect to take to reduce your demand and/or to increase your supply of power from sources other than your proposed plant that are either alternate fuel-fired or qualify for other exemptions.

(6) Calculation of your expected date of termination for your period of impairment. You may specify several alternative termination dates, each corresponding to a different combination of major events that are beyond your control (such as slippages of a new plant being built by a different utility in your electrical region);

(7) An explanation of why there is not enough time to construct an alternate fuel-fired plant to prevent impairment of reliability of service;

(8) An explanation of why you believe that modification of the powerplant to permit compliance with the Act is technically infeasible;

(9) An explanation of why you believe that modification of the powerplant to permit compliance with the Act would result in unreasonable expense;

(10) In addition, you may include other evidence that you believe is relevant to your case, such as:

(i) Evidence that the reliability advantages of coordination on an electric region basis cannot be achieved to an extent sufficient to remove your "impairment of reliability," reasons for this deficiency, and an estimate of when such coordination could be implemented in your region; or

(ii) Evidence that your system has a unique situation that requires the use of different reliability criteria.

(c) *Liability for operating in excess of exemption.* The operation of a peakload powerplant which has been granted this exemption in excess of that allowed by the exemption shall be subject to penalties under Title VII, Subtitle C of the Act unless the powerplant meets the criteria set forth in section 721(c) of the Act.

(d) *Reporting requirement.* If the petition is granted, you must report to ERA, at the end of each 12-month period from the effective date of the exemption and, if applicable, upon reaching the maximum number of kilowatt hours of permitted generation within each 12-month period, the name, location, and design capacity of the exempted unit, the number of hours of operation permitted by the exemption, and the number of hours of actual operation.

§ 504.39 Intermediate load powerplants.

(a) *Eligibility.* Section 312(g) of the Act provides for an exemption for use of petroleum as a primary energy source by intermediate load powerplants. ERA may grant you such an exemption if you demonstrate to the satisfaction of ERA that:

(1) The Administrator of the EPA or the Director of the appropriate State air pollution control agency has certified that the use of any available alternate fuel as a primary energy source will cause or contribute to a concentration, in an air quality control region or any area within such region, of a pollutant for which any national ambient air quality standard is or would be exceeded as described in paragraph (c) of this section:

(2) The powerplant as operated will replace no more than the equivalent generating capacity of existing units which:

(i) Permanently cease operation within one month of ERA's granting the intermediate load powerplant this exemption;

(ii) Use natural gas or petroleum as a primary energy source;

(iii) Are owned by the same person who is to operate the existing powerplant; and

(iv) Would, if they burned coal, cause or contribute to a pollutant concentration in a manner described in paragraph (a)(1) of this section;

(3) The powerplant is and shall continue to be operated only as an intermediate load powerplant in which the electrical generation (in kilowatt hours) for any 12-calendar-month period, shall not exceed the powerplant's design capacity mulitplied by 3,500 hours;

(4) The net heat input rate for the powerplant will be maintained at or less that 9,500 BTU's per kilowatt hour throughout the remaining useful life of the powerplant;

(5) The powerplant has the capability to use a synthetic fuel derived from an alternate fuel as a primary energy source.

(b) *Evidence supporting the petition.* Your must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) An air quality certification for this unit prepared by the EPA or State air pollution control agency, meeting the requirements of paragraph (a)(1) of this section, including a listing of all alternate fuels covered by the certification;

(2) A description of the existing powerplants to be replaced, by the intermediate load powerplant which shall include:

(i) The name and location of each of the existing powerplants;

(ii) The volume of fuel consumed by type for the previous two years by the existing powerplants;

(iii) The corporate ownership of the existing powerplants; and

(iv) The reasons for claiming that the existing powerplants would cause or contribute to a pollutant concentration if they used coal as a primary energy source.

(3) An affidavit executed by a duly authorized officer of the electric utility which will operate the powerplant certifying that the powerplant shall be operated at all times in the future only as an intermediate load powerplant. The certification shall set forth the design capacity of the powerplant and the maximum allowable generation of the powerplant in kilowatt hours for its first 12 months of operation from the date the petition for exemption is filed.

(4) An affidavit executed by a duly authorized officer and a qualified engineer of the operating utility of the powerplant certifying that the powerplant can operate at a heat rate of 9,500 btu's per kilowatt hour or less throughout the useful life of the powerplant;

(5) An affidavit executed by a duly authorized officer and a qualified engineer of the operating utility certifying that the powerplant has the synthetic fuels capability requirement described in paragraph (a)(5) of this section, identifying the specific synthetic fuels, and agreeing to cease using petroleum or natural gas when ERA has found that such synthetic fuels are available;

(6) Identification of the synthetic fuel(s) your existing powerplant is designed to use, with appropriate documentation including:

(i) Your expected source of synthetic fuel, if known;

(ii) The year when you expect the synthetic fuel to be available in adequate quantity at an acceptable price;

(iii) Estimates of the future prices of the synthetic fuel your plant is designed to use;

(iv) Your role, if any, in developing the facilities to produce the synthetic fuels; and

(v) Your basis for believing that these fuels can be burned in your plant in conformance with applicable Federal and state environmental standards.

(c) *Terms and conditions.* ERA, if it grants you this exemption, will set as a condition the amount of oil to be used by the existing powerplant. In general, ERA would require that the granting of this exemption result in a reduction in oil use or a reduction in the rate of oil increase by your system. The reduced oil use would be achieved by ceasing operation of the applicable existing units and by employing the more efficient proposed unit in their place.

(d) *Reporting Requirement.* If the petition is granted, you must report to ERA, at the end of each 12 month period from the first day of the month following the effective date of the exemption and, if applicable upon reaching the maximum number of hours of permitted operation within each 12 month period, the name, location and design capacity of the exempt unit, the number of hours of operation permitted by the exemption, the number of hours of actual operation. You must also report at the same time the amount of petroleum used by the unit and the total amount of petroleum used by all units in your system.

(e) *Periodic Review.* ERA shall, from time to time, review this exemption and shall terminate it when it finds that there is available a supply of synthetic fuel suitable for use by the exempt powerplant.

(f) *Exercise of discretion by ERA.* ERA may refuse to grant this exemption to you if it determines that such grant would not be in the public interest in accordance with the purposes of the Act, notwithstanding the fact that the evidence you have furnished to ERA in your exemption petition substantiates that your facility would otherwise be eligible to receive the exemption.

§ 504.40 Use of natural gas by powerplants with capacity of less than 250 million Btu's per hour.

(a) *Eligibility.* Section 312(h) of FUA provides for a permanent exemption for the use of natural gas by powerplants with a capacity of 250 million Btu's per hour or less. To qualify you must demonstrate to the satisfaction of ERA that:

(1) The design capacity of the powerplant for consuming fuel (or mixture thereof) is less than a heat input rate of 250 million Btu's per hour;

(2) The electrical generation of the powerplant during calendar year 1977 exceeded, in kilowatt hours, the powerplants design capacity multiplied by 3500 hours; and

(3) The powerplant is not capable of burning coal without—

(i) Substantial physical modification of the unit, as determined on a case-by-case basis in accordance with the policy expressed in § 500.1. However for the purposes of this provision, ERA shall exclude pollution control equipment; or

(ii) Substantial reduction in the rated capacity of the unit, as determined on a case-by-case basis in accordance with the policy expressed in § 500.1. However for the purposes of this provision, ERA shall not consider a derating of less than 10% to be substantial.

(b) *Evidence required to support the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) The purchaser's design specifications and date of installation for the powerplant;

(2) A detailed history of the fuel consumption of the powerplant for 1976 and 1977 on a monthly basis for each fuel consumed; and

(3) An itemized list of the modifications required to burn coal as a primary energy source, the estimated cost for each modification, and the time required to make these modifications, to include copies of all pertinent engineering documents utilized to arrive at these estimates;

(4) The derating factor, if any, anticipated from burning coal as a primary energy source in the unit(s) and a detailed description of the formulas and assumptions used to arrive at that factor.

(c) *Restrictions.* This exemption may only apply to the prohibitions under Section 301 of FUA and prohibitions by final rules or orders issued before January 1, 1990.

§ 504.41 Use of liquefied natural gas.

(a) *Eligibility.* Section 312(i) of the Act provides for a permanent exemption for the use of liquefied natural gas (LNG). To qualify you must demonstrate to the satisfaction of ERA that:

(1) The Administrator of the EPA or the appropriate State air pollution control agency has certified that the use of coal, including any available coal derived fuel, as a primary energy source will cause or contribute to a concentration, in an air quality control region or any area within such region, of a pollutant for which any national ambient air quality standard is or would be exceeded (air quality certification);

(2) The Administrator of the EPA or the appropriate State air pollution control agency has certified that you will be unable to use coal, including any available coal derived fuel as a primary energy source without violating applicable environmental requirements (environmental certification); and

(3) The LNG to be used at your powerplant will be produced outside the continental United States.

(b) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) Copies of your applications for an air quality certification and an environmental certification filed with the EPA or State air pollution control agency which request certification for coal and all available coal derived fuels, and copies of all supporting documentation filed with or subsequent to the applications; and

(2) The name of the country or state that will be the source of your LNG the name of the company that owns the LNG terminal through which your LNG will be imported and the name and location of such terminal, and the name of the company that will be supplying you with LNG.

(c) *Air quality certification.* Your petition is not complete unless the following have been submitted to ERA:

(1) A certification of the EPA or the appropriate State air pollution control agency that the use by the powerplant of coal or any available coal-derived fuel as a primary energy source will cause or contribute to a concentration, in an air quality control region or any area within such region, of a pollutant for which any national ambient air quality standard is or would be exceeded and that your use of coal or any available coal-derived fuel would not comply with applicable environmental requirements; and

(2) A statement indicating which fuels were presented for consideration to the agency which certified with regard to the Clean Air Act, and, to the extent known by you, why they were rejected as a method of compliance.

(d) *Reporting requirement.* If the petition is granted, you must report to ERA, at the end of each 12 month period from the first day of the month following the effective date of the exemption and, if applicable, upon reaching the maximum number of hours of permitted operation within each 12 month period, the name, location and design capacity of the exempt unit, the number of hours of operation permitted by the exemption, the number of hours of actual operation, and efforts taken to seek and obtain a synthetic fuel for use in the powerplants.

(e) *Enforcement.* Violations of the provisions of this exemption shall subject you to the maximum penalties provided for by Part 501, Subpart L of these regulations.

PART 506—EXISTING MAJOR FUEL BURNING INSTALLATIONS

Subpart A—Prohibitions

Authority: Department of Energy Organization Act, Pub. L. 95-91, 91 Stat. 565 (42 U.S.C. 7101 et seq.); Powerplant and Industrial Fuel Use Act of 1978, Pub. L. 95-620, 92 Stat. 3289 (42 U.S.C. 8301 et seq.); E.O. 12009, 42 FR 46267.

PART 506—EXISTING MAJOR FUEL BURNING INSTALLATIONS

Subpart A—Prohibitions

§ 506.1 Purpose and scope.

This subpart sets forth prohibitions imposed on existing major fuel burning installations. The prohibitions set forth in this subpart apply to all existing major fuel burning installations, as defined in § 500.2, unless an exemption has been granted by ERA under Subparts C and D of this part. Any person who owns, controls, rents or leases an installation is subject to the prohibitions imposed and the sanctions provided for by the Act or these regulations.

§ 506.2 Prohibitions by order (case-by-case).

(a) ERA may prohibit, by order, the use of natural gas or petroleum as a primary energy source in an existing major fuel burning installation if ERA finds that:

(1) The installation has, or previously had, the technical capability to use an alternate fuel as a primary energy source;

(2) The installation has this technical capability, or it could have the technical capability again without;

(i) A substantial physical modification of the installation; or

(ii) A substantial reduction in the rated capacity of the installation; and

(3) It is financially feasible for the installation to use an alternate fuel as its primary energy source.

(b) ERA must make a proposed finding regarding the technical capability of a unit to use alternate fuel as identified in paragraph (a)(1) of this section prior to the date of publication of the notice of the proposed prohibition. ERA will publish this finding in the Federal Register along with the notice of the proposed prohibition.

(c) The findings enable ERA to assess the potential impact of a prohibition order on three levels: The impact on the facility itself, the impact on the economic activity which the steam or electric power supports, and the impact on the parent firm owning the site. Where the regulation reflects an emphasis on one level or another in a particular finding, ERA has based such emphasis on the terms of the legislation, the conference report, and its own identification of the most appropriate level in accordance with its regulatory discretion.

(d) *Technical capability.* (1) ERA will consider "technical capability" on a case-by-case basis. In making this assessment however, ERA will only consider the characteristics of the unit itself and will not ordinarily consider the nature or absence of appurtenances outside the unit. ERA's major concern is the ability of the unit, from the point of fuel intake to physically sustain combustion of a given fuel and to maintain heat transfer.[1]

(2) ERA considers that a unit "had" the technical capability to use an alternate fuel if the unit was once able to burn that fuel (regardless of whether the unit was expressly designed to burn that fuel or whether it ever actually did burn it) but is no longer able to do so at the present due to temporary or permanent alterations to the unit itself.[2]

(3) A unit "has" the technical capability to use an alternate fuel if it can burn an alternate fuel, notwithstanding the fact that minor adjustments must be made to the unit beforehand or that pollution control equipment may be required to meet air quality requirements.[3]

(e) *Substantial physical modifications.* ERA will make its determination on whether a physical modification to a unit is "substantial" on a case-by-case basis. ERA will consider physical modifications made to the unit as "substantial" where warranted by the magnitude and complexity of the engineering task or where the modification would impact severely upon operations at the site.[4] ERA will not, however, assess physical modification on the basis of cost or the installation of pollution control or fuel handling equipment.

(f) *Substantial reduction in rated capacity.* (1) ERA will assess units for which a derating of 10% or more is claimed on a case-by-case basis. ERA does not consider a derating of less than 10% as a result of converting a unit from

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[1] For example, ERA will examine the furnace configuration and ash removal capability but will not normally consider the need to install pollution control equipment as a measure of technical capability. Furthermore, ERA will not conclude that the absence of fuel handling equipment, such as conveyor belts, pulverizers, capability" to burn an alternate fuel.

[2] For example, a unit which at one time burned solid coal, but which could no longer do so because its coal firing ports and sluicing channels had been cemented over, would be classified as having "had" the technical capability to use coal. (The queston of whether it again "could have" such capability without "substantial physical modification" is a separate and additional question.)

[3] A unit designed to burn natural gas also "has" the technical capability to burn medium Btu gas from coal (assuming such gas is available). Also a unit designed to burn oil may, depending upon the chemical characteristics, be a unit that "has" the technical capability to burn liquefied coal. The fact that certain minor adjustments may be necessary does not render this a "hypothetical" as opposed to a "real" capability. Even an oil fired unit converting from the use of #2 distillate to #6 residual oil may be required to adjust or replace burner nozzles and add soot blowers. ERA views these alterations as minor adjustments the need for which does not render a unit incapable of burning a particular fuel.

[4] Significant alterations affecting the furnace configuration or a complete respacing of the tubes would likely fall into this category. A combination of modifications involving changes required for bottom ash removal, related construction and engineering work, and other modifications to the boiler, other than furnace configuration or tube spacing may, in some circumstances, cause modifications to be considered substantial.

oil or gas to an alternate fuel to be "substantial" under any circumstances.[5]

(2) In assessing whether a unit's derating of 10% or more is "substantial", ERA will consider the impact of the reduction in available capacity on the site at which the facility is located as well as on the unit itself.[6]

(g) *Financial feasibility.* (1) It is financially feasible for your installation to use an alternate fuel as its primary energy source if the cost of using an alternate fuel does not substantially exceed the cost of using imported petroleum using the general cost calculation described in § 504.12(a) and (b) of the regulations. However, in making this cost calculation, you may use your firm's real cost of capital [7] as the discount rate for the purpose of computing cost, rather than the average, real cost of capital required for installations as specified in § 506.12 of these regulations; and

(2) You may seek to rebut this presumption by evidence that despite good faith efforts you are unable to raise the capital that would be necessary for the conversion, or that for some other economic or financial reason, conversion is not financially feasible. The standard for assessing capital availability will be identified to that specified in § 505.25 (inability to obtain adequate capital).

(3) In making this determination, ERA will consider any relevant factor presented by the proposed order recipient which bears upon the competitive viability of the facility or loss of production if any, at the facility during the period required for the conversion.

(h) *Mixtures finding.* (1) If ERA finds that it is technically and financially feasible for your powerplant to use a mixture of petroleum or natural gas and alternate fuel as its primary energy source, ERA may prohibit you, by order, from using petroleum or natural gas in amounts exceeding the minimum amount necessary to maintain the reliability of your operation consistent with maintaining reasonable fuel efficiency of the mixture. (Such minimum amount determined by ERA shall not be less than 25 percent.)

(2) In making the technical feasibility finding, ERA may weigh "physical modification" or "derating of the unit;" but these considerations, by themselves, will not control the technical feasibility finding. A technical feasibility finding might be made notwithstanding the need for substantial physical modification. The economic consequences of a substantial physical modification are taken into account in determining financial feasibility.

(3) The authority of ERA implemented under this section should not be confused with the two other fuel mixture provisions of these regulations. One is the requirement that petitioners for permanent exemptions need demonstrate that the use of a mixture of natural gas or petroleum and an alternate fuel is not economically or technically feasible (§§ 504.15 and 506.14). The second is the permanent fuel mixtures exemptions themselves (see §§ 504.36 and 506.36).

Subpart B—General Requirements for Exemptions

§ 506.10 Purpose and scope.

This subpart establishes the general requirements necessary to qualify for either a temporary or permanent exemption from the prohibitions set out under this part and establishes the methodology for calculating the cost of using an alternate fuel and the cost of using imported petroleum.

§ 506.11 Fuels decision report.

(a) Before ERA will accept a petition for either a temporary or permanent exemption from a final prohibition order issued under this part, you must include as part of your petition a Fuels Decision Report as described in Part 502 unless you are requesting an emergency purposes or retirement exemption. The Fuels Decision Report shall contain the analysis and documentation of the evidence required in support of your exemption request.

(b) Your petition may contain more than one exemption request. In this case, your petition would include one Fuels Decision Report which addresses your considerations and the appropriate forms for the exemptions you are requesting.

§ 506.12 Cost calculations for existing installations.

(a) *General.* (1) This calculation compares the cost of using alternate fuel to the cost of using imported petroleum. Its purpose is to provide ERA with a mechanism for deciding when investments that are not the best economic choice from the viewpoint of the individual firm are nevertheless economic in light of the benefits and costs to the United States.

(2) The cost of using an alternate fuel in lieu of imported oil or gas as a primary energy source will be deemed to be substantially in excess of the cost of using imported petroleum where the ratio of the former to the latter is greater than the index set periodically by ERA.

(3) The index is currently 1.3. ERA will revise the index from time to time after public notice and time to comment. Revisions shall become effective for all ERA decisions after final publications; however, the relevant index for a specific petition will be the index in effect at the time the petition is submitted, or the index in effect at the time a decision is rendered, whichever is lower.

(4) The cost test takes into consideration cash outlays for capital investments and annual expenses, and the effect of depreciation and taxes on the cash flow. There are two comparative cost tests—a general cost test and a special cost test. You must demonstrate eligibility for a permanent exemption using the procedures specified in the general cost test (section b). You must demonstrate eligibility for a temporary exemption using the procedures specified in the general cost test (section b) or the special cost test (section c).

(5) The general cost test differs from the special cost test with respect to the time period over which costs are calculated. When using the general cost test, the cost is computed for the remaining useful life of the installation. When using the special cost test, the cost is computed only for the term of the exemption.

(b) *Cost Calculation—General Cost Test.* (1) You may be eligible for a permanent exemption if you demonstrate that the cost of using an alternate fuel starting anytime within the first 10 years of the exemption will always substantially exceed the cost of using imported petroleum from the time the exemption becomes effective until the end of the powerplant's remaining useful life. You will have to show that the cost of using an alternate fuel, starting in each of the first 10 years of the exemption and using oil or natural

[5] Typically, units that are the subject of a prohibition order will not have installed any operating air pollution control equipment sufficient to burn coal in compliance with applicable environmental equipments. The installation and use of air pollution control equipment alone can, in many cases, produce a derating of close to 10 percent. Moreover, the shift to coal itself will, because of differences in energy density and fuel flow characteristics typically involve some derating. Thus if a derating of less than 10 percent could constitute a "substantial" derating, the authority conferred by Congress to prohibit by order could be almost entirely nugatory.

[6] For example, ERA may find that the derating of a unit far in excess of 10 percent is not "substantial" if it produces no appreciable effect upon the operations of a facility with considerable excess capacity.

[7] For the purposes of these interim regulations, you must compute the real cost of capital according to the procedures outlined in appendix I of these regulations.

gas until the start of using an alternate fuel, substantially exceeds the cost of using only imported petroleum.

(2) If the discounted lifetime cost of alternative fuel use, computed with successive starting date for the first 10 years of the exemption, does not always substantially exceed the cost of using imported petroleum, you would only be eligible for a temporary exemption. The length of the temporary exemption would be for the minimum period within which the cost of starting to use alternate fuel always substantially exceeds the cost of using imported petroleum. For example, if you can burn coal and it cannot be obtained at a reasonable price for 2 years, ERA may grant a temporary exemption and allow the burning of oil for 2 years.

(3) to conduct the test, you must use the equations that follow.

(i) Calculate the ratio (R) of the cost of using an alternate fuel to the cost of using imported petroleum with equation 1.

EQ 3
$$I = I_D + \sum_{i=-g}^{N} \frac{I_i - ITC_i - S_i}{(1+K)^i}$$

(ii) Calculate the cost of using an alternate fuel and imported petroleum with equation 2.

EQ 2
$$COST = I + \sum_{i=1}^{N} \frac{(OM_i + FL_i)(1-t) - t(DPR_i)}{(1+K)^i}$$

(iii) Calculate the capital investment using equation 3.

EQ 1
$$R = \frac{COST\ (ALTERNATE)}{COST\ (OIL)}$$

(4) The terms in equations 2 and 3 are defined as follows:

i=Year. Outlays before the proposed exemption becomes effective are future valued to the year before the year before the proposed exemption becomes effective (year 0) and outlays after the proposed exemption becomes effective are present valued to the year before the proposed exemption becomes effective.
g=The number of years prior to the year before the proposed exemption becomes effective a cash outlay is made for capital investments or investment tax credit is used.
N=The remaining useful life of the installation (see section d).
I_D=Capital investment required to recover the capacity lost due to derating (see section d).
I_i=Yearly cash outlay (in dollars) from the year the outlays first occur to the last year of the installation's remaining useful life for capital investments (see section d).
OM_i=Annual cash outlay in year i (in dollars) for all operations and maintenance expenses except fuel (i.e., all non-capital and non-fuel cash outlays caused by putting the capital investments into service). May include labor, materials, insurance, taxes (except income taxes), etc. (see section d).
t=Marginal income tax rate (see section d).
FL_i=Annual cash outlay for delivered fuel expenses (in dollars) in year i (see section d).
K=The discount rate expressed as a fraction (see section d).
DPR_i=Depreciation in year i (see section d).
S_i=Salvage value of capital investment (in dollars) realized in year i.
ITC_i=Federal investment tax credit resulting from capital investment used in year i (see section d).

(5) The step-by-step procedure that follows shows the comparison that you must make. It outlines the fuel and time comparisons.

(i) Compute the cost (COST) of using an alternate fuel throughout the remaining useful life of the installation with equation 2.

(ii) Compute the cost (COST) of using oil or natural gas throughout the remaining life of the installation with equation 2.

(iii) Compute the ratio (R) of the cost of using an alternate fuel throughout the remaining useful life of the installation to the cost of using oil or natural gas throughout the remaining useful life of the installation with equation 1. If the ratio (R) is equal to or less than 1.3, the index set by ERA, you are not eligible for a permanent or temporary exemption using the general cost test and need not complete the remainder of the calculation.

(iv) Compute the cost (COST) of using an alternate fuel with equation 2 assuming an alternate fuel is not used as the primary energy source until the end of the first year of the exemption and that oil or natural gas is used for the first year of the exemption. All cash outlays should reflect postponed use of alternate fuel (e.g., installation of scrubber when used).

(v) Successively compute the cost (COST) of using an alternate fuel with equation 2 assuming alternate fuel is postponed until the end of the second through tenth year of the exemption (and oil or natural gas is used in the years preceding alternate fuel use).

(vi) Compute the ratios (R) of the cost of using an alternate fuel successively at the end of the first through tenth year (and using oil or natural gas in the years preceding alternate fuel use) to the cost of using oil or natural gas throughout the remaining useful life of the installation with equation 1.

(vii) If all the ratios (R) computed in iii and vi are greater than 1.3 (an index to be set periodically by ERA), a permanent exemption would be granted. If one or more of the ratios (R) is equal to or less than 1.3 and a series of ratios (R), starting with the case where alternate fuel is used from the start of the exemption, are all greater than 1.3, a temporary exemption would be granted for the minimum period in which the cost of starting to use alternate fuel, deferred year by year, always exceeds 1.3.

(6) The following table shows the hypothetical results of four sets of calculations assuming the index is 1.3.

Hypothetical Results of Four Sets of Calculations

Year in which alternate fuel use commences	Case I	Case II	Case III	Case IV
At start of exemption	1.4	1.6	1.5	1.1
End of year:				
1	1.4	1.6	1.5	1.1
2	1.5	1.7	1.5	1.2
3	1.3	1.6	1.4	1.2
4	1.3	1.5	1.3	1.1
5	1.2	1.5	1.4	1.1
6	1.2	1.4	1.4	1.1
7	1.1	1.4	1.5	1.1
8	1.1	1.4	1.5	1.1
9	1.0	1.4	1.6	1.1
10	1.0	1.4	1.6	1.1

The results of the above table show that: a 2-year temporary exemption would be granted in Case I, a permanent exemption would be granted in Case II, a 3-year temporary exemption would be granted in Case III, and no exemption would be granted in Case IV.

(c) *Cost calculation—special cost test.* (1) You may be eligible for a temporary exemption if you demonstrate that the cost of using an alternate fuel will substantially exceed the cost of using oil or natural gas over the period of the proposed exemption. The period of the exemption cannot exceed 10 years. You will have to show that the cost of using an alternate fuel substantially exceeds the cost of using imported petroleum for the first year of the exemption, the first 2 years of the exemption, and successive first years of the exemption, up to the period of the proposed exemption. To do so, you must perform the calculations with successive ending dates to determine the maximum length of the exemption. ERA will limit the duration of a temporary exemption to the shortest time possible.

(2) To conduct the test, you must use the equations that follow.

(i) Calculate the ratio (R) of the cost of using an alternate fuel to the cost of using imported petroleum with equation 4.

$$\text{EQ 4} \qquad R = \frac{\text{COST (ALTERNATE)}}{\text{COST (OIL)}}$$

(ii) Calculate the cost using equation 5.

$$\text{EQ 5} \qquad \text{COST} = I \times \frac{\sum_{i=1}^{P} (1+K)^{-i}}{\sum_{i=1}^{N} (1+K)^{-i}} + \sum_{i=1}^{P} \frac{(OM_i + FL_i)(1-t) - t(DPR_i)}{(1+K)^i}$$

(3) The terms in equation 5 are the same as in equation 2 above with the addition of:

P The length of the proposed temporary exemption.

(4) The step-by-step procedure that follows shows the comparisons you must make.

(i) Compute the cost (COST) of using an alternate fuel assuming the length of the proposed exemption is 1 year with equation 5.

(ii) Compute the cost (COST) of using oil or natural gas assuming the length of the proposed exemption is 1 year with equation 5.

(iii) Compute the ratio (R) of the cost of using an alternate fuel for the first year to the cost of using imported petroleum for the first year with equation 4.

(iv) Repeat the calculations made in i, ii, and iii above assuming the length of the proposed exemption is 2 years, 3 years, 4 years, and so on, up to the period of the proposed exemption.

(v) A temporary exemption would be granted when all the ratios (R) are greater than 1.3 (the index established by ERA).

(d) *Information on parameters used in the calculation.* (1) All estimated expenditures, except natural gas and petroleum products, shall be expressed in real (uninflated) terms by using the prices in effect at the time the petition is submitted.

(2) The delivered price of oil or natural gas used in the calculation of delivered fuel expenses must reflect the price of imported oil.

(i) If you use 100 percent domestic[8] petroleum product in your facility, compute your petroleum price with equation 6.

EQ 6 PFE=PF+PICO−PCCO

The terms of equation 6 are defined as follows:

PICO=Price of imported crude oil. The most recent refiner acquisition cost of imported crude oil as reported in the Federal Register monthly notice for the DOE Domestic Crude Oil Allocation (Entitlements) Program.

PCCO=Price of composite crude oil. The most recent weighted average cost of total reported crude oil receipts as reported in the Federal Register notice for the DOE Entitlements Programs.

PF=Price of your fuel oil (f.o.b. your facility). The most recent actual weighted average cost of your fuel (other than natural gas). Alternatively, if no purchase of fuel oil occurred, or you used natural gas during that month, you should use a simple average of the industrial price of fuel oil (capable of being burned in your facility) sold in your area by at least three suppliers.

PFE=Price of fuel for use in the cost calculation.

(ii) If you use 100 percent imported petroleum product in your facility, compute your petroleum price with equation 7.

EQ 7 PFE=PF+ENT

The terms of equation 7 are the same as equation 6 with the additions of:

ENT = ½ x E_p x DOSR for residual fuel oil if an entitlement has been received by the importer.

ENT = 0 for all other products or if an entitlement has not been received by the importer.

E_p = entitlement priced reported in the Federal Register monthly notice for the DOE Entitlements Program.

DOSR = national domestic oil supply ratio reported in the Federal Register monthly notice for the DOE Entitlements Program.

(iii) If you use a combination of domestic and imported petroleum product in your facility, you may use the prices computed with the formula in paragraph (a) of this section or you may use a weighted average of the prices computed with the formulas in paragraphs (a) and (b) of this section.

(iv) If you use natural gas in your facility, you must use the formula in paragraph (d)(2) of this section and the price of #6 residual fuel oil, which meets the air quality standards in your area, as the price of fuel.

(3) Capital investment yearly cash outlays (I_i) must include all items which are capital investments for Federal income tax purposes. All purchased equipment which has a useful life greater than 1 year, capitalized engineering costs, land, construction, environmental offsets, fuel inventory,[9] piping, etc., required to use the installation being converted required after the proposed exemption would become effective must be included. However, an item may only be included if a cash outlay is required after the decision has been made to convert (or not to convert) the installation.

(4) Capital investment, if any, required to recover the lost capacity due to derating (I_D) must be computed with equation 8 if an election is made to recover that capacity.[10]

$$\text{EQ 3} \quad I_D = \frac{\sum_{i=1}^{N} (1+K)^{-i}}{\sum_{i=1}^{M} (1+K)^{-i}} \times \sum_{i=-g}^{M} \frac{I^D - ITC^D_i - S^D_i}{(1+K)^i}$$

(i) M, I_i^D, ITC_i^D, and S_i^D are the useful life, yearly investment cash outlays, investment tax credits, and the salvage values respectively resulting from the purchase of equipment required to recover the capacity lost due to derating; all definitions and information which apply to N, I_i, ITC_i, S_i, apply to M, I^D_i, ITC^D_i, and S^D_i except that M, I_i^D, ITC_i^D, and S_i^D are limited to equipment required to recover the capacity lost due to derating. All other terms are as in equation 3.

(ii) If an election is made not to recover the capacity lost due to derating, the capital investment required to recover the lost capacity due to derating equals zero.

(5)(i) The annual operating and maintenance expenses (OM_i) and the fuel expenses (FL_i) are computed using one of the following methods; however the one chosen must be consistently applied throughout the analyses. They are:

(A) Assume the installation will annually generate an amount of energy or steam equal to the average amount of energy or steam produced annually for

[8] For the purpose of this regulation, the Virgin Islands, Puerto Rico, and the U.S. territories and possessions are domestic sources.

[9] For industrial boilers, the greater of: 1) 21 days fuel supply, or 2) sufficient fuel to fill 60% of the storage volume must be included. If you already have oil in inventory, it must be salvaged.

[10] If the capacity is recovered, the cash flows must result in the least cost feasible solution (i.e., the cost computed with equation 2 or 5 must be the lowest feasible cost).

the last 5 years (or the life of the installation if it is less than 5 years).

(B) Base the computations on the actual power or steam generation schedule.[11]

(ii) If you use the methodology as set out in paragraph (d)(5)(i)(A) of this section the operations and maintenance expenses must include both fixed and variable components.

(iii) If an exemption is granted, it will be conditioned, subject to penalties, upon the petitioner burning no more than the maximum amount of fuel he could have specified and still have been granted the exemption.

(6) The discount rate (K) is 7.7 percent. ERA will change the discount rate from time to time after public notice and an opportunity to comment. Revisions shall become effective after final publication; however, the relevant discount rate for a specific petition will be the discount rate in effect at the time the petition is submitted.

(7) The remaining useful life (N) of major fuel burning installations shall be 40 years minus the number of years of operation prior to the effective date of the proposed exemption. You may rebut this presumption with suitable engineering evidence.

(8) All Federal investment tax credits (ITC_i) will be applied consistently throughout the analysis in a manner consistent with the Federal tax laws in effect at the time the petition is submitted.

(9) Depreciation (DPR_i) will be applied consistently through the analysis in a manner consistent with Federal tax laws in effect at the time the petition is submitted. Depreciation on both the original installation and the capital investment required due to the conversion must be included. In general, accelerated depreciation cannot be used for new gas- or oil-fired boilers. You must use the most rapid depreciation permitted by law for capital investments required to burn alternate fuel.

(10) The marginal income tax rate (t) is the firm's marginal Federal income tax rate for the year the petition is submitted.

(11) All estimated expenditures will be computed in accordance with generally accepted accounting principles.

(e) *Evidence in support of the comparative cost test.* All petitions for exemption requiring the use of the comparative cost test shall include, but not be limited to, the following information:

(1) A detailed accounting of all cash outlays, investment tax credits, and anticipated salvage value for capital investments. Include a description and cost estimate of all major construction and equipment. All critical assumptions should be stated and sufficient data should be included to support your estimates.

(2) A detailed accounting of all annual cash outlays for fixed and variable operations and maintenance expenses including a description of all major elements and the formulas used to compute them. All critical assumptions should be stated and sufficient data included to support your estimates.

(3) A detailed accounting of all annual cash outlays for delivered fuel expenses including the formulas used to compute them. All critical assumptions should be stated and sufficient data included to support your estimates. The fuel price and characteristic for each alternative fuel should be included.

(4) If the remaining useful life of the installation is judged to be less than 40 years minus the number of years of operation prior to the effective date of the proposed exemption, all critical assumptions and sufficient data to support that position.

(5) A detailed accounting of the depreciation for each capital asset including the depreciable base, tax life and methods used. All critical assumptions should be stated and sufficient data included to support your estimates.

(6) A detailed justification of the 5 year average amount of energy or steam produced or, if your base your computations on the actual power or steam generation schedule, a detailed justification or your power or steam generation schedule.

(f) *Example of calculations.* (1) The purpose of this example is solely to illustrate the mechanics of the cost tests; it should not be construed to be guidance on the application of the Federal income tax laws. The detail is only to the level of the individual terms in the cost test equations. Where the petitioner should supply a value, equations, and data, we have only supplied the value.

(2) We are assuming that you are profitable to the extent that your Federal marginal income tax rate is 46 percent and that you need not carry over investment tax credits.

(3) You are considering converting an oil-fired major fuel burning installation to coal. In this particular situation, the delivery cost of coal is much greater for the first 3 years than it will be in the later years because of a transportation problem requiring 3 years to resolve. Do you qualify for an exemption? If so, is it permanent or temporary?

(4) To determine if you qualify for a permanent exemption, you would have to use the general cost test and compute the ratios of the cost to use (i) coal for the remaining useful life of the installation, (ii) oil for the first year of the exemption and coal for the remainder of the remaining useful life of the installation, (iii) oil for the first 2 years of the exemption and coal for the remainder of the remaining useful life of the installation, * * *, and (iv) oil for the first 10 years of the exemption and coal for the remainder of the remaining useful life of the installation to the cost of using oil for the entire remaining useful life of the installation.

(5) All 11 ratios would have to be higher than, for purposes of this example, 1.3 in order to qualify for a permanent exemption. However, if a series of successive ratios, starting with the case where alternate fuel is used from the start of the exemption, are all greater than 1.3, you would be eligible for a temporary exemption up to the last year the ratio is greater than 1.3.

(6) In this example, we will only compute the ratios of (i) the cost to use coal for the remaining useful life of the installation and (ii) the cost to use oil for the first 3 years of the exemption and coal for the remainder of the remaining useful life of the installatin to the cost of using oil for the entire remaining useful life of the installation.

(7) To determine if you qualify for a temporary exemption, if you have not already done so with the general cost test, of 3 years, you would have to use the special cost test and compute the ratios of the cost to use coal to the cost to use oil for 1, 2, and 3 years. All three ratios would have to be higher than 1.3 in order to qualify for a 3 year temporary exemption. In this example, we will only compute the ratio of the cost to use coal to the cost to use oil for 3 years.

(8) *Parameters.* A set of hypothetical parameters are given below. The installation is a 200,000,000 BTU/HR Boiler.

(i) *Capital cash flow requirements.* The cash flow required to make the installation coal-capable are:

	Cash flow
Year before boiler becomes coal-capable:	
−1	314,000
0	906,000
Total	1,220,000

[11] If the capacity lost due to derating is recovered, you must use this method and the cash flows must result in the least cost feasible solution (i.e., the cost computed with equation 2 or 5 must be the lowest feasible cost).

It is assumed that this is all pollution control equipment.

(ii) *Operations and Maintenance Expense Cash Flow Requirements.*

(A) When burning oil—

Fixed	371,000
Variable	100,000
Total	471,000

(B) When burning coal:

Fixed	1,449,000
Variable	540,000
Total	1,989,000

(iii) *Fuel Expense Cash Requirements.*

(A) When burning oil:

First through 25th year	2,742,000

(B) When burning coal—

First 3 years	2,460,000
Fourth through 25th year	1,640,000

(iv) The installation is assumed to have a current book value of 1,465,000 and a remaining tax life of 8 years.

$$COST = I + \sum_{i=1}^{N} \frac{(OM_i + FL_i)\ (1-t) - t(DPR_i)}{(1+K)^i}$$

$$= 1132 + \sum_{i=1}^{3} \frac{(1,989 + 2,460)\ (1 - 0.46)}{(1.08)^i}$$

$$+ \sum_{i=4}^{25} \frac{(1,989 + 1,640)\ (1 - 0.46)}{(1.08)^i}$$

$$- \sum_{i=1}^{8} \frac{0.46 \times DPR_i\ 14/}{(1.08)^i} - \sum_{i=1}^{25} \frac{0.46 \times DPR_i\ 15/}{(1.08)^i}$$

$$= 22,324$$

(B) Compute the cost of using oil for the remaining useful life of the installation.

$$COST = I + \sum_{i=1}^{N} \frac{(OM_i+FL_i)\ (1-t) - t(DPR_i)}{(1+K)^i}$$

$$= 0 + \sum_{i=1}^{25} \frac{(471 + 2,742)\ (1 - 0.46)}{(1.08)^i}$$

$$- \sum_{i=1}^{8} \frac{0.46 \times (DPR_i)\ 16}{(1.08)^i}$$

$$= 18,037$$

(v) The discount rate for the purpose of this example is 8 percent.

(vi) The installation has been operational for 15 years. Its remaining useful life is 25 years.

(vii) It is assumed that no derating is involved.

(9) *Analysis* [12]

(i) *General Cost Test.*

(A) Compute the cost of using coal from the start of the exemption.

$$I = \sum_{i=-g}^{N} \frac{I_i - ITC_i - S_i}{(1+K)^i}$$

$$= \frac{314}{(1.08)^{-1}} + \frac{906}{(1.08)^0} - \frac{0.10 \times 1,220\ 13/}{(1.08)}$$

$$I = 1132$$

(C) Compute the ratio of the cost of using coal from the beginning of the exemption to the cost of using oil throughout the remaining useful life of the boiler.

$$R = \frac{COST\ (COAL)}{COST\ (OIL)} = \frac{22,324}{18,037} = 1.24$$

The ratio (R) is less than 1.3. Therefore you are not eligible for a permanent or temporary exemption using the general cost test and need not complete the calculation. However for illustrative purpose, we will continue.

(D) Compute the cost of using coal assuming coal is not used until after the third year and oil is used for the first 3 years of the exemption.

$$I = \sum_{i=-g}^{N} \frac{I_i - ITC_i - S_i}{(1+K)^i}$$

$$= \frac{314}{(1.08)^2} + \frac{906}{(1.08)^3} - \frac{0.10 \times 1,220\ 17/}{(1.08)^4}$$

$$I = 899$$

$$COST\ 0 + \sum_{i=1}^{N} \frac{(OM_i + FL_i)\ (1-t) - t(DPR_i)}{(1+K)^i}$$

$$= 899$$

$$+ \sum_{i=1}^{3} \frac{(471 + 2,742)\ (1 - 0.46)}{(1.08)^i}$$

$$+ \sum_{i=4}^{25} \frac{(1,989 + 1,640)\ (1 - 0.46)}{(1.08)^i}$$

$$- \sum_{i=1}^{8} \frac{0.46 \times DPR_i\ 18/}{(1.08)^i} - \sum_{i=4}^{25} \frac{0.46 \times DPR_i\ 19/}{(1.08)^i}$$

$$COST = 20,371$$

(E) Compute the ratio of the cost of using coal starting at the end of the third year to the cost of using oil throughout the remaining life of the boiler.

[12] All dollars are in thousands.

[13] ITC is recognized the year the equipment is put into operation.

[14] This term accounts for the depreciation of the original installation. Current book value is 1,465 and straight line depreciation is being taken over 8 more years.

[15] This term accounts for the depreciation of the capital investment (pollution control equipment) necessary to burn coal. The depreciation method is the rapid amortization method used for certified pollution control equipment added to an installation in existence before 1976. The tax life is 25 years.

[16] This term accounts for the depreciation of the original installation. Current book value is 1,465 and straight line depreciation is being taken over 8 more years.

[17] ITC is recognized the year after the boiler becomes coal capable.

[18] This term accounts for the depreciation of the original installation. Current book value is 1,465 and straight line depreciation is being taken over 8 more years.

[19] This term accounts for the depreciation of the capital investment (pollution control equipment) required to burn coal. The depreciation method is the rapid amortization method used for certified pollution control equipment added to an installation in existence before 1976. The tax life is 22 years.

$$R = \frac{\text{COST (COAL)}}{\text{COST (OIL)}} = \frac{20{,}371}{18{,}037} = 1.13$$

(ii) *Special Cost Test.*

(A) Compute the cost of using coal assuming the length of the exemption is 3 years.

$$\text{COST} = I \times \frac{\sum_{i=1}^{P} (1+K)^{-i}}{\sum_{i=1}^{N} (1+K)^{-i}} + \sum_{i=1}^{P} \frac{(OM_i + FL_i)\ (1-t)\ - t(DPR_i)}{(1+K)^i}$$

$$= 1{,}132 \times \frac{\sum_{i=1}^{3} (1.08)^{-i}}{\sum_{i=1}^{25} (1.08)^{-i}} + \sum_{i=1}^{3} \frac{(1{,}989 + 2{,}640)\ (1 - 0.46)}{(1.08)^i}$$

$$- \sum_{i=1}^{3} \frac{0.46 \times DPR_i\,\text{[20]}}{(1.08)^i} - \sum_{i=1}^{3} \frac{0.46 \times DPR_i\,\text{[21]}}{(1.08)^i}$$

$$= 6{,}104$$

(B) Compute the cost of using oil assuming the exemption is 3 years.

$$\text{COST} = I \times \frac{\sum_{i=1}^{P} (1+K)^{-i}}{\sum_{i=1}^{N} (1+K)^{-i}} + \sum_{i=1}^{P} \frac{(OM_i + FL_i)\ (1-t) - t(DPR_i)}{(1+K)^i}$$

$$= 899 \times \frac{\sum_{i=1}^{3} (1.08)^{-i}}{\sum_{i=1}^{25} (1.08)^{-i}} + \sum_{i=1}^{3} \frac{(471 + 2{,}742)\ (1 - 0.46)}{(1.08)^i}$$

$$- \sum_{i=1}^{3} \frac{0.46 \times DPR_i\,\text{[22]}}{(1.08)^i}$$

$$= 4544$$

(C) Compute the ratio of the cost of using coal to the cost of using oil.

$$R = \frac{\text{COST (COAL)}}{\text{COST (OIL)}} = \frac{6104}{4544} = 1.34$$

This ratio (R) is greater than 1.3. You would receive a temporary exemption of three years, if the ratios computed where the use of coal is delayed one and two years are also higher than 1.3.

[20] This terms accounts for the depreciation for the depreciation of the original installation. Current book value is 1,465 and straight line depreciation is taken over 8 more years.

[21] This term accounts for the depreciation of the capital investment (pollution control equipment) necessary to burn coal. The depreciation method is the rapid amortization method used for certified pollution control equipment added to a plant in existence before 1976. The tax life is 25 years.

[22] This term amounts for the depreciation of the original installation. Current book value is 1,464 and straight line depreciation is taken over 8 more years.

§ 506.13 [Reserved]

§ 506.14 Use of mixtures—General requirements for permanent exemptions.

(a) *Application.* ERA will not consider a petition for any of the following exemptions provided for in Section 312 of the Act (lack of alternate fuel supply, site limitations, environmental requirements, cogeneration, emergency purposes, product/process requirements, or scheduled equipment outages) to be complete, adequate, or acceptable for filing unless you demonstrate to the satisfaction of ERA in your petition that you have considered the use of a mixture(s) for which an exemption under § 506.36 (Fuel mixtures) of these regulations would be available.

(b) *Demonstration.* ERA will deny petitions for any of the exemptions listed above unless you demonstrate that use of such a mixture(s) is not economically or technically feasible in the unit for which you are requesting an exemption. You must submit to ERA in your Fuels Decision Report (or in your petition for an emergency or retirement exemption) at least the following evidence in order to make the demonstration required by this section:

(1) If use of a mixture(s) were required, you would be eligible for one of the following permanent exemptions provided for in the Act: lack of alternate fuel supply, site limitations, environmental requirements, or state or local requirements; or

(2) The use of a mixture(s) is not technically or economically feasible in your specific unit due to design or special circumstances.

§ 506.15 Use of fluidized bed combustion not feasible—General requirement for permanent exemptions.

(a) *ERA Finding.* ERA may deny any of the following permanent exemptions provided for in Section 312 of the Act (lack of alternate fuel supply, site limitations, environmental requirements, state or local requirements, cogeneration, emergency purposes, product/process, or equipment outages), if ERA finds on a site specific or generic basis that use of a method of fluidized bed combustion of an alternate fuel is economically and technically feasible.

(b) *Demonstration.* If ERA has made such a finding, ERA will deny your request for exemption unless you demonstrate that the use of a method of fluidized bed combustion is not economically or technically feasible. You must include in your Fuels Decision Report or any supplement thereto required by ERA (or in your petition for an emergency or retirement exemption) at least the following evidence:

(1) If use of a method of fluidized bed combustion were required, you would be eligible for one of the following permanent exemptions provided for in Section 312 of the Act: lack of alternate fuel supply, site limitations, environmental requirements, or state or local requirements; or

(2) Use of a method of fluidized bed combustion is not technically or

economically feasible in your specific unit due to design or special circumstances.

§ 506.16 Terms and conditions; compliance plans.

(a) *Terms and conditions generally.* You must comply with the terms and conditions of an exemption granted under the Act by ERA, including terms and conditions requiring the use of effective fuel conservation measures.

(b) *Compliance plans for temporary exemptions.*

(1) A compliance plan certified by your duly authorized representative must accompany each petition for a temporary exemption. The compliance plan shall include at least the following:

(i) A specific schedule of milestones indicating how you will comply with the applicable prohibitions of the Act;

(ii) Evidence of binding contracts for fuel or facilities for the production of fuel which are needed to comply with the applicable prohibitions of the Act; and

(iii) Any other documentary evidence which indicates your ability to comply with the applicable prohibitions of the Act.

(2) The exemption shall not be effective until the compliance plan is approved by ERA.

(3) *Revisions of compliance plans.* If the petition is granted, you must submit to ERA an updated compliance plan certified by your duly authorized representative.

(i) At the end of each 12 month period from the effective date of the exemption;

(ii) Within one month of an alteration of any milestone in the compliance plan, together with the reasons for the alteration and its impact upon the scheduling of all other milestones in the plan; and

(iii) At any time the ERA, in its discretion, determines that a revised compliance plan is necessary to reflect changes in circumstances.

(c) *Enforcement.* Any exemption is subject to termination upon the violation of any provision of the exemption or any provision of the pertinent compliance plan.

Subpart C—Temporary Exemptions for Existing Major Fuel Burning Installations

§ 506.20 Purpose and scope.

(a) This subpart implements the provisions contained in Section 311 of the Act with regard to temporary exemptions for existing installations.

(b) This subpart establishes the criteria and standards which owners or operators of existing installations who petition for a temporary exemption must meet to sustain their burden of proof under the Act.

(c) All petitions for temporary exemptions for existing installations must be submitted in accordance with the procedures set out in Part 501 of these regulations.

(d) The duration of any temporary exemption granted under this subpart shall be measured from the date that the applicable prohibition would first apply if the exemption had not been granted.

§ 506.21 Lack of alternate fuel supply.

(a) *Eligibility.* Section 311(a)(1) of the Act provides for a temporary exemption due to the unavailability of an adequate and reliable supply of an alternate fuel. To qualify you must demonstrate to the satisfaction of ERA that:

(1) You made a good faith effort to obtain an adequate and reliable supply of an alternate fuel for use as a primary energy source of the quality and quantity necessary to conform with the design and operational requirements of the existing installation;

(2) For the period of the proposed exemption, the cost of using such a supply would substantially exceed the cost of using imported petroleum as a primary energy source as defined in § 506.12 (Cost Calculation) of these regulations; and

(3) You will be able to comply with the applicable prohibitions of these regulations at the end of the proposed exemption period.

(b) *Evidence required in support of a petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) A description of your analysis of the alternate fuels you considered for use;

(2) A description of the detailed design requirements you specified for the existing installation including capacity, alternate fuel capability, and all other specifications;

(3) A description of the range of specific fuel characteristics of all the fuels which can be used by the existing installation;

(4) Evidence that you sought to obtain the full range of alternate fuels and fuel characteristics which could be used by the existing installation, including bid requests and/or advertisements for supply contracts and all responses thereto, as well as any other arrangements you attempted to make to secure supplies;

(5) Evidence of the contracts or other arrangements you have made to insure a reliable and adequate supply of an alternate fuel at the end of the proposed exemption: and

(6) All data required by § 506.12 (Cost Calculation) necessary for computing the cost calculation formula.

(c) *Compliance Plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 506.16 of these regulations simultaneously with submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 506.16 of these regulations and as may be required by the terms of any order granting an exemption under this subpart.

(d) *Duration.* This temporary exemption, taking into account any extensions or renewals, may not exceed ten years.

§ 506.22 Site limitations.

(a) *Eligibility.* Section 311(a)(2) of the Act provides for a temporary exemption due to a site limitation. To qualify for such an exemption you must demonstrate, to the satisfaction of the ERA, that one or more of the following specific physical limitations relevant to the location or operation of your installation exist which, despite your diligent good faith efforts, cannot be overcome before the end of the proposed exemption period:

(1) Alternate fuels would be inaccessible as a result of a specific physical limitation relevant to the operation of the existing installation;

(2) Transportation facilities for alternate fuels would be unavailable;

(3) Adequate land or facilities for handling, using or storing an alternate fuel would be unavailable;

(4) Adequate means for controlling and disposing of wastes would be unavailable;

(5) Adequate and reliable supply of water would be unavailable; or

(6) Other site limitations exist which would not permit the operation of the existing installation using an alternate fuel;

(b) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) Evidence that the site limitation is a physical limitation, and not a requirement of a Federal, state or local law which could be the basis of an exemption under § 506.34 (State or local requirements);

(2) Evidence that alternate means for overcoming the specific site limitations were considered, with a detailed description of the efforts made to

overcome the site limitations set out in your petition;

(3) Evidence of the equipment or space requirements for which the site limitation is claimed;

(4) Evidence of the contracts or other arrangements you have made to insure that the site limitation will be overcome and that you will be able to comply with the applicable prohibitions at the end of the proposed exemption period. Examples of evidence relevant to establishing a site limitation for purposes of a temporary exemption are as follows:

(i) Detailed documentation of impediments, including rights of way problems, site diagrams, maps of the surrounding area and other items essential to the showing of a site limitation;

(ii) Identification of transportation facilities relevant to the specific site of the installation and a demonstration why existing transportation facilities cannot be utilized or new facilities constructed;

(iii) Copies of bid requests, advertisements and general efforts made to secure alternate transportation facilities;

(iv) Identification of potential fuel storage locations within a reasonable geographic area surrounding the existing installation;

(v) Detailed scale site plans of the entire facility which include those areas not directly involved with the specific installation;

(vi) A specific listing of all equipment necessary and not currently available to properly handle alternate fuel;

(vii) Copies of bid requests, advertisements and general efforts made to secure alternative fuel storage facilities;

(viii) Copies of quotes from bona fide suppliers, indicating lead times for purchase and installation of required ancillary storage or handling equipment;

(ix) Specific listing of any equipment necessary and not currently available to properly control and dispose of waste;

(x) Identification of potential alternate waste disposal locations within a reasonable geographic area surrounding the existing installation;

(xi) A description of efforts made to secure offsite disposal areas, including the cost of acquisition of the sites, transportation facilities and waste handling costs involved in their use; and

(xii) Copies of bid requests, advertisements, and general efforts made to secure waste control and disposal equipment.

(c) *Compliance plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 506.16 of these regulations simultaneously with submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 506.16 of these regulations and as may be required by the terms of any order granting an exemption under this subpart.

(d) *Duration.* This temporary exemption, taking into account any extensions and renewals, may not exceed five years.

§ 506.23 Inability to comply with applicable environmental requirements.

(a) *Eligibility.* Section 311(a)(3) of the Act provides for a temporary exemption due to an inability to comply with applicable environmental requirements. To qualify you must demonstrate to the satisfaction of ERA that despite diligent good faith efforts:

(1) You are are unable to comply with the applicable prohibitions imposed by without violating applicable Federal or state environmental requirements; and

(2) You will be able to comply with the applicable prohibitions imposed by the Act and with applicable environmental requirements by the end of the temporary exemption period.

(b) *Criteria.* ERA's decision with regard to environmental compliance will be based solely on an analysis of your capacity to physically achieve applicable environmental requirements. You should direct your analysis toward those conditions or circumstances which make it physically impossible for you to comply with applicable environmental requirements during the temporary exemption period. Cost of compliance shall not enter into the analysis, but any cost-related considerations may be presented as part of a demonstration submitted under § 506.21.

(c) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required in this section:

(1) An examination of the environmental compliance of the facility, including an analysis of the ability to meet applicable standards and criteria when using both the proposed fuel and all alternate fuels with reference to which you are requesting an environmental exemption. All conclusions regarding the ability of the facility to comply must be based on accepted analytical techniques, such as air quality modeling, and must reflect current conditions of the area which would be affected by the facility. You are responsible for performing the necessary sampling and collecting sufficient data to accurately characterize these conditions. Environmental compliance must be examined in the context of the available pollution control equipment which would provide the maximum possible reduction of pollution. The analysis must contain requests for bids and other inquiries made and responses received by you concerning the availability and performance of pollution control equipment; contracts signed, if any, for an alternate fuel supply and for the purchase and installation of pollution control equipment; or other comparable evidence such as technical studies documenting efficacy of equipment to meet applicable requirements; and

(2) An examination of the regulatory options available to you in seeking to achieve environmental compliance. This must include an analysis of the availability of offsets, if needed, and the potential for securing variances and State Implementation Plan revisions, as appropriate. The analysis must illustrate and document your efforts, if any, to locate, identify, and acquire offsets, including agreements made by you with the State or other companies for acquisition of offsets. If an agreement to acquire offsets is conditioned upon the grant of a variance, or State Implementation Plan revision, you must submit a letter from the State agency indicating when a proceeding to effectuate the agreement will take place. The analysis must contain any correspondence initiated or received by you concerning these regulatory options and all technical studies you have relied upon to support your conclusions.

In addition, you may submit any other documentation you believe demonstrates an inability to comply with applicable environmental requirements despite diligent good faith efforts.

(d) *Compliance Plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 506.16 of these regulations simultaneously with the submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 506.16 of these reulations and as may be required by the terms of any order granting an exemption under this subpart.

(e) *Other Actions.* Prior to deciding to submit an exemption application, it is recommended that you request a meeting with ERA and EPA or the appropriate State or local regulatory agency to discuss options for operating an alternate fuel-fired facility in compliance with applicable environemental requirements.

(f) *Duration.* This temporary exemption, taking into account extensions and renewals, may not exceed five years, and will be issued by ERA for such time period up to and including five years as the petition demonstrates is necessary.

§ 506.24 Future use of synthetic fuels.

(a) *Eligibility.* Section 311(b) of the Act provides for a temporary exemption based upon the future use of synthetic fuels. To qualify you must demonstrate to the satisfaction of ERA that:

(1) You will be able to comply with the applicable prohibitions at the end of the proposed exemption period by the use of synthetic fuel as a primary energy source in your installation; and

(2) You will not be capable of complying with the applicable prohibitions by using synthetic fuel in your installation before the end of the proposed exemption period.

(b) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) Copies of economic and technical feasibility studies pertaining to the use of synthetic fuels by your installation;

(2) Reliable evidence of the financial commitments you have made to construct, operate and maintain equipment which will use synthetic fuel as the primary energy source at the end of the proposed exemption period;

(3) Copies of bid requests, advertisements, contracts and/or other agreements relating to the production, purchase, and transportation of synthetic fuel; and

(4) Information with regard to permits that may be required by Federal or state agencies for the operation of an installation using synthetic fuels.

(c) *Compliance plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 506.16 of these regulations simultaneously with submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 506.16 of these regulations and as may be required by the terms of any order granting an exemption under this subpart.

(d) *Duration.* This temporary exemption may be granted for a period of up to five years and may be extended for an additional five years, but so extended may not exceed ten years.

§ 506.25 Use of innovative technologies.

(a) *Eligibility.* Section 311(c) of the Act provides for a temporary exemption based on the use of innovative technologies. To qualify you must demonstrate to the satisfaction of ERA that you will be able to comply with the applicable rule or order at the end of the proposed exemption period by adoption of a technology for the use of an alternate fuel which ERA determines to be an innovative technology.

(b) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) Copies of economic and technical feasibility studies pertaining to adoption of an innovative technology for use of an alternate fuel in your installation;

(2) A complete description of the innovative technology you propose to use including explanation of its innovative characteristics, detailed design and engineering specifications, and a description of the fuel characteristics of the alternate fuels which can be used with the innovative technology.

(3) Reliable evidence of the financial and contractual commitments you have made to construct or modify, operate, and maintain equipment which represents an innovative technology for the use of alternate fuel and which will be used at the end of the proposed exemption period; and

(4) Copies of bid requests, advertisements, contracts, and/or other arrangements you have made to insure a reliable and adequate supply of an alternate fuel at the end of the proposed exemption.

(c) *Compliance plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 506.16 of these regulations simultaneously with submission of your petition. You must submit an updated compliance plan, if applicable, as required by § 506.16 of these regulations and as may be required by the terms and conditions of any order granting an exemption under this subpart.

(d) *Other action.* Prior to deciding to submit an exemption application, it is recommended that you request a pre-petition conference with ERA to discuss the requirements of this exemption.

(e) *Duration.* This temporary exemption may be granted for a period of up to 5 years and may be extended for an additional 5 years, but so extended may not exceed 10 years.

§ 506.26 Retirement.

(a) *Eligibility.* Section 311(d) of the Act provides for a temporary exemption for retirement. To qualify you must demonstrate to the satisfaction of ERA that the installation will be retired at the expiration of this temporary exemption.

(b) *Evidence required in support of the petition.* You must include in your petition at least the following evidence in order to make the demonstration required by this section:

(1) A detailed engineering analysis explaining why the installation cannot use alternate fuels prior to retirement;

(2) Any other documentary evidence which indicates the reasons for retirement and plans for replacement or substitution of the retired installation;

(c) *Compliance plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 506.16 of the regulations simultaneously with submission of the petition. You must submit an updated compliance plan, if applicable, as required by § 506.16 except § 506.16 (b)(1) (ii) of these regulations and by the terms of any order granting an exemption under this subpart.

(d) *Duration.* This temporary exemption, taking into account extensions and renewals, may not exceed 5 years.

(e) *Restriction.* In the event this exemption is granted you will not be eligible for any other exemption under Title III, Subtitle B of the Act.

§ 506.27 Public interest exemption.

(a) *Policy note.* The use of coal and other alternate fuels in lieu of petroleum and natural gas is in the public interest. ERA will grant this temporary exemption where you are unable to comply immediately with the prohibitions of an order or rule, where the granting of the petition would be in the public interest, and where you will be in compliance with the prohibitions at the end of the exemption period. In filing your petition, you are required to complete the portions of the Fuels Decision Report (FDR) specified in section 502 of these interim Rules and demonstrate why your proposed facility could not burn a fuel mixture during the time the exemption is in effect. ERA recognizes, however, that there are situations where the public interest would best be served by not requiring the FDR and mixture demonstration; consequently, ERA strongly urges you to request a prepetition conference where, after a consideration of the facts of your case, ERA could waive all or part of these requirements.

(b) *Eligibility.* Section 311(e) of the Act provides for a temporary public interest exemption. To qualify, you must demonstrate to the satisfaction of ERA that:

(1) You are unable to comply with the applicable prohibitions, imposed by the Act, except in extraordinary circumstances, during the period for which the exemption is requested, but that you will be capable of complying at the end of the proposed exemption period; and

(2) The granting of the petition would be in accord with the purposes of the Act and would be in that public interest.

(c) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) Substantial evidence to corroborate the eligibility requirements identified above;

(2) A demonstration that the use of a mixture for which an exemption under § 506.36 (Fuel Mixtures) would be available, is not technically or economically feasible during the period the temporary public interest exemption is in effect; and

(3) Information and data required by § 502.4 (Introduction), § 502.7 (Evidence for exemption required), and § 502.12 (Conservation measures) of the Fuels Decision Report as set out in Part 502.

(d) *Compliance Plan.* You must submit to ERA a compliance plan in accordance with section 314 of the Act and § 506.16 of these regulations simultaneously with submission of your petition. You must submit, if applicable, an updated compliance plan as required by § 506.16 of these regulations and as may be required by the terms of any order granting an exemption under this subpart.

(e) *Duration.* This temporary exemption, taking into account extension and renewals, may not exceed 5 years.

Subpart D—Permanent Exemptions for Existing MFBI's

§ 506.30 Purpose and scope.

(a) This subpart implements the provisions contained in Section 312 of the Act with regard to permanent exemptions for existing major fuel burning installations.

(b) This subpart establishes the criteria and standards which owners or operators of existing installations who petition for a permanent exemption must meet to sustain their burden of proof under the Act.

(c) If a petition for a permanent exemption is filed pursuant to § 506.31 (lack of alternate fuel supply); § 506.32 (site limitations); § 506.33 (Inability to comply with applicable environmental requirements); or § 506.34 (State or local requirements), you must demonstrate in your Fuels Decision Report that your inability to use each reasonable alternate fuel would entitle you to one or more of the above exemptions.

(d) All petitions for permanent exemptions for existing installations must be submitted in accordance with the procedures set out in part 501 of these regulations.

§ 506.31 Lack of alternate fuel supply.

(a) *Eligibility.* Section 312(a)(1)(A) of the Act provides for a permanent exemption due to lack of an alternate fuel supply at a cost which does not substantially exceed the cost of using imported oil. To qualify, you must demonstrate to the satisfaction of ERA that:

(1) You made a good faith effort to obtain an adequate and reliable supply of an alternate fuel for use as a primary energy source of the quality and quantity necessary to conform to design and operational requirements of the existing installation; and

(2) The cost of using such a supply would substantially exceed the cost of using imported petroleum as a primary energy source, as defined in § 506.12 (Cost Calculation) of these regulations during the remaining useful life of the existing installation.

(b) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) A description of the detailed design requirements you specified for the existing installation, including capacity, alternate fuels capability, and all other pertinent specifications;

(2) A description of the range of specific fuel characteristics of all the fuels which can be used by the existing installations;

(3) Evidence that you sought the full range of alternate fuels which could be used by the existing installation, including bid requests, and/or advertisements for supply contracts, all responses you received, as well as any other arrangements you attempted to make to secure supplies;

(4) All data required by § 506.12 of these regulations (Cost Calculation) necessary for computing the cost calculation formula; and

(5) A description of your analysis of the alternate fuels you considered.

§ 506.32 Site limitations.

(a) *Eligibility.* Section 312(a)(1)(B) of the Act provides for a permanent exemption due to a site limitation. To qualify you must demonstrate to the satisfaction of the ERA that, despite good faith efforts:

(1) Alternate fuels would be inaccessible to the operation of the existing installation as a result of a specific physical limitation;

(2) Transportation facilities for alternate fuels would be unavailable;

(3) Adequate land or facilities for handling, using or storing alternate fuels would be unavailable;

(4) Adequate means for controlling and disposing of wastes would be unavailable;

(5) An adequate and reliable supply of water would be unavailable; or

(6) Other site limitations exist which would not permit the operation of the existing installation using an alternate fuel and that these limitations cannot be reasonably expected to be overcome within five years after effective date of the applicable prohibition.

(b) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) Evidence that the site limitation is a physical limitation, and not a requirement of a Federal, state, or local law which could be the basis of an exemption under § 506.34 (State or local requirements);

(2) Evidence that alternate means for overcoming the specific site limitation were sought, with a detailed description of the efforts made to overcome the site limitation set out in your petition; and

(3) Evidence of the necessary equipment or space requirements for which the site limitation is claimed. Examples of evidence relevant to establishing a site limitation for purposes of a permanent exemption are as follows:

(i) Detailed documentation of impediments, including right-of-way problems, site diagrams, maps of the surrounding areas and other essentials to the showing of a site limitation;

(ii) Identification of transportation facilities relevant to the geographic site of the installation and a demonstration showing why existing transportation facilities cannot be utilized or new facilities constructed;

(iii) Copies of bid requests, advertisements and general efforts made to secure alternative transportation facilities;

(iv) Identification of potential alternate fuel storage locations within a reasonable geographic area surrounding the installation;

(v) Detailed scale site plans of the entire facility which include those areas not directly involved with the specific installation;

(vi) A specific listing of all equipment necessary and not currently available to properly handle alternate fuels;

(vii) Copies of bid requests, advertisements and general efforts made to secure alternate storage facilities;

(viii) Copies of quotes from bona fide suppliers indicating lead times for purchase and installation of required ancillary storage or handling equipment;

(ix) Specific listing of any equipment necessary and not currently available to properly control and dispose of waste;

(x) Identification of potential alternate waste disposal locations within a reasonable geographic area surrounding the installation;

(xi) A description of efforts made to secure off site disposal areas, transportation facilities and waste handling costs involved in their use; and

(xii) Copies of bid requests, advertisements, and general efforts made to secure waste control and disposal equipment.

§ 506.33 Inability to comply with applicable environmental requirements.

(a) *Eligibility.* Section 312 (a)(1)(C) of the Act provides for a permanent exemption due to inability to comply with applicable environmental requirements. To qualify you must demonstrate to the satisfaction of ERA that, despite good faith efforts, you cannot burn alternate fuel without violating applicable environmental requirements within 5 years of the date the exemption is requested to take effect.

(b) *Criteria.* ERA's decision with regard to compliance will be based solely on an analysis of your capacity to physically achieve applicable environmental requirements. The cost of compliance shall not enter into the analysis, but any cost-related considerations may be presented as part of a demonstration submitted under § 506.31.

(c) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence to make the demonstration required by this section:

(1) An examination of the environmental compliance of the facility, including an analysis of the ability to meet applicable standards and criteria when using both the proposed fuel and all alternative fuels with reference to which you are requesting an environmental exemption. All conclusions regarding the ability of the facility to comply must be based on accepted analytical techniques, such as air quality modeling, and must reflect current conditions of the area which would be affected by the facility. You are responsible for performing the necessary sampling and collecting sufficient data to accurately characterize these conditions. Environmental compliance must be examined in the context of the available pollution control equipment which would provide the maximum possible reduction of pollution. The analysis must contain requests for bids and other inquiries made and responses received by you concerning the availability and performance of pollution control equipment, or other comparable evidence such as technical studies documenting efficiency of equipment to meet applicable requirements; and

(2) An examination of the regulatory options available to you in seeking to achieve environmental compliance. This must include an analysis of the availability of offsets, if needed, and the potential for securing variances and State Implementation Plan revisions, as appropriate. The analysis must illustrate and document your efforts, if any, to locate and identify available offsets, and to secure variances and SIP revisions. The analysis must contain any correspondence initiated or received by you concerning these regulatory options and all technical studies you have relied upon to support your conclusions.

(3) In addition, you may submit any other documentation you believe demonstrates an inability to comply with applicable environmental requirements despite good faith efforts.

(d) *Other Actions.* Prior to deciding to submit an exemption application, it is recommended that you request a meeting with ERA and EPA or the appropriate state or local regulatory agency to discuss options for operating an alternate fuel-fired facility in compliance with the applicable environmental requirements.

§ 506.34 State or local requirements.

(a) *Eligibility.* Section 312(b) of the Act provides for a permanent exemption due to state or local requirements which would preclude the operation of an alternate fuel-fired installation. To qualify, you must demonstrate to the satisfaction of ERA that:

(1) With respect to the site of the installation, the operation of such installation using an alternate fuel is infeasible because of a state or local requirement;

(2) If such state or local requirement is under a building code or nuisance or zoning law, no other exemption could be granted for such facility;

(3) You have in good faith attempted unsuccessfully to obtain a variance or waiver from the state or local requirement or can demonstrate why none is available;

(4) The granting of the exemption would be in the public interest and would be consistent with the purposes of the Act; and

(5) You are not entitled to any other exemption if the State or local requirement is under a building code or nuisance or zoning law.

(b) *Evidence required in support of a petition.* You must include in your Fuels Decision Report at least the following evidence to make the demonstration required by this section:

(1) A copy of the pertinent State or local requirement with its citation and its legislative history;

(2) The identification and location of the administrative body which implements the requirement;

(3) A description of your attempts to obtain a waiver or variance from the requirements or a demonstration of why none is available;

(4) A description of any activities you were involved in after April 20, 1977, pertaining to the enactment of the requirement;

(5) A description of equipment, procedures, and the advance planning time necessary to comply with the requirement;

(6) A detailed description of why compliance with the State or local requirement is infeasible;

(7) The impact upon you and/or your local community, if any, should your petition be denied;

(8) An explanation of the reasons why granting this exemption would be in the public interest; and

(9) An analysis of why you cannot qualify for any other exemption if the State or local requirement is under a building code or nuisance or zoning law.

(c) *Exercise of discretion by ERA.* ERA may refuse to grant this exemption to you if it determines that such grant would not be in the public interest or in accordance with the purposes of the Act, notwithstanding the fact that the evidence you have furnished to ERA in your exemption petition substantiates that your facility would otherwise be eligible to receive the exemption.

§ 506.35 Cogeneration.

(a) *Eligibility.* Section 312(c) of the Act provides for a permanent exemption for cogeneration. To qualify you must demonstrate to the satisfaction of ERA at least the following minimum criteria:

(1) The oil or gas to be consumed by the cogeneration facility will be less

than that which would otherwise be consumed in the absence of the cogeneration facility where the calculation of savings is in accordance with paragraph (c) of this section;

(2) It would be in the public interest to grant an exemption to the cogeneration facility because of special circumstances such as technical innovation or maintaining industry in urban areas.

(b) *Specifications of the cogeneration facility.* (1) A person proposing to operate a cogeneration facility may apply for an exemption under this section if the amount of net electricity that is either sold or exchanged is less than 50 percent. If the amount is 50 percent or more, see § 504.35 (Powerplants). Net electricity excludes sales or exchanges among owners of the cogeneration facility.

(2) Electricity generated by the cogeneration facility must constitute more than 10 percent of the useful energy output of the facility and less than 90 percent of the useful energy output.

(c) *Calculation of oil and gas savings.* There is an oil and gas savings if the oil or gas to be consumed by the cogeneration facility will be less than that which would otherwise be consumed in the absence of the cogeneration facility. The calculation of the oil and gas which would otherwise be consumed must be in accordance with paragraphs (c) (1) and (2) of this section.

(1) Except for the case described in paragaphs (c)(2) of this section, the oil or gas which would otherwise be consumed must be calculated as follows:

(i) You may include the oil or gas that would be consumed by facilities that are or would be too small to be covered by the FUA regulations. In the case of new small industrial units, you must demonstrate that it would be reasonable to construct units of that size.

(ii) You may include the oil or gas that would be consumed by units in place (existing or exempt) covered by FUA if they are less than 40 years old in the case of a field-erected unit or less than 20 years old in the case of a package unit. In the case of existing units, you may not include units that have burned an alternate fuel or are capable of burning an alternate fuel, and, you may only include units described by this paragraph if they will be retired or shut down if this exemption is granted.

(iii) You may include the oil or gas that would be consumed by units not yet constructed that would be covered by the FUA regulations if you can demonstrate that each unit would be entitled to an exemption.

(iv) You may include the oil or gas that would be consumed by powerplants to generate electricity supplied to the grid to the extent that such electricity, if you cogenerate, will no longer be supplied by the grid. The oil or gas portion must be based on a 10 year forecast that includes new construction and retirement of plants within those 10 years.

(2) In the case of a cogeneration facility that would consist of an existing unit or an exempted unit and a new unit, you must calculate the amount of oil or gas that would otherwise be consumed as the sum of:

(i) The five-year annual average oil or gas consumption of the existing or exempted unit; and

(ii) The amount that would be consumed in units described in paragraphs (c)(1)–(i) (iv) of this section that would now be satisfied by the cogeneration facility.

(d) *Evidence required in support of a petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) An engineering description of the cogeneration system, including output and uses thereof, with sufficient detail to ensure that the facility qualifies as a cogeneration facility;

(2) A detailed oil and natural gas savings calculation identifyng the projected oil or natural gas consumption of the cogeneration facility and the oil or natural gas that would otherwise be used;

(3) Identification of the FUA staus of the units described in paragraph (c)(1) (i)–(iv) of this section with respect to coverage and designation as new, existing, or exempted, age of units, and alternate fuel capability of units;

(4) Identification of all persons and their roles in the cogeneration facility; and

(5) In the case of paragraph (a)(2) of this section, an explanation of the public interest factors you believe should be considered by ERA.

(e) *Exercise of discretion by ERA.* ERA may refuse to grant this exemption to you if it determines that such grant would not be in the public interest or in accordance with the purposes of the Act, notwithstanding the fact that the evidence you have furnished to ERA in your exemption petition substantiates that your facility would otherwise be eligible to receive this exemption.

§ 506.36 Permanent exemptions for certain fuel mixtures containing natural gas or petroleum.

(a) *Eligibility.* Section 312(d) of the Act provides for a permanent exemption for certain fuel mixtures. To qualify you must demonstrate to the satisfaction of ERA that:

(1) You propose to use a mixture of natural gas or petroleum and an alternate fuel as a primary energy source; and

(2) The amount of petroleum or natural gas you propose to use in the mixture will not exceed the minimum percentage of the total BTU heat input needed to maintain operational reliability of the installation consistent with maintaining a reasonable level of fuel efficiency.

(b) *Minimum percentage.* If the exemption is granted, ERA will not require that the percentage of petroleum or natural gas used in the mixture be less than 25% of the total annual BTU heat input of the installation.

(c) *Evidence required in support of a petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) A complete description of the fuel mixture, component elements of the mixture, and percentage of each component to be utilized;

(2) The design specifications for the unit for which you are requesting an exemption;

(3) An engineering assessment of the proportions of petroleum or natural gas needed to maintain operational reliability and an adequate level of fuel efficiency; or

(4) If the unit will use a mixture containing less than 25 percent petroleum or natural gas, a certification that the amount of petroleum or natural gas you propose to use in the mixture will not exceed 25 percent of the total annual Btu heat input of the installation. The certification shall be executed by your duly authorized representative.

(d) *Reporting requirement.* If the exemption is granted you must submit an annual report to ERA certifying that the affected units have used no more than the percentage of oil or natural gas specified in the exemption order. The certification shall be executed by your duly authorized representative.

(e) *Solar mixtures.* ERA will grant a permanent mixture exemption for the use of a mixture of solar energy (including wind, tide, and other intermittent sources) and petroleum or natural gas, where—

(1) Solar energy will account for at least 20 percent of the annual BTU heat input of the unit; and

(2) You propose an acceptable plan to ERA which—

(i) Meets the evidence requirements set forth in paragraph (c) of this section; and

(ii) Contains a compliance plan prepared in accordance with § 506.16 of these regulations.

§ 506.37 Emergency purposes.

(a) *Eligibility.* Section 312(e) of the Act provides for a permanent exemption for emergency purposes. To qualify you must demonstrate to the satisfaction of ERA that you will operate and maintain the installation for emergency purposes only.

(b) *Definition.* For the purposes of this permanent exemption, an emergency exists when operation of an oil or gas-fired installation is necessary for (1) plant protection; or (2) the preservation of human health; or (3) continued facility production which otherwise would be reduced due to an interruption of alternate fuel supplies, equipment failures, or temporary environmental restrictions.

(c) *Evidence required in support of a petition.* You must include in your petition at least the following evidence:

(1) Certification executed by a duly authorized officer of the company stating that operation under the provisions of this exemption will occur only in accordance with the definition of emergency;

(2) A description of the other units of the site including for each the capacity, type of fuel consumed, average utilization rate, designation as "new" or "existing" under this program, and exemption, if any;

(3) A description of the types of emergency situations you believe may arise which cause you to request this exemption;

(4) All data required by § 506.7 (Use of mixtures—general requirement) of these regulations demonstrating that use of a mixture(s) is not economically or technically feasible; and

(5) All data required by § 506.8 (Use of fluidized bed combustion not feasible—general requirement) if ERA has made a generic or site-specific finding that the use of a method of fluidized bed combustion of an alternate fuel is economically and technically feasible.

(d) *Additional information.* You must submit the following additional information:

(1) All data required by § 502.11 (Petroleum and natural gas use) of these regulations;

(2) All data required by § 502.12 (Conservation measures) of these regulations which describe any oil or natural gas conservation measures you have taken or intend to take if the exemption is granted; and

(3) All data required by § 502.13 (Environmental impacts analysis) of these regulations which will assist ERA to fulfill its responsibilities under the National Environmental Policy Act (NEPA).

(e) *Reporting Requirement.* At the end of each 12-month period from the effective date of the exemption, you must report to ERA the amount of fuel used under this exemption by month. You must also describe the emergency conditions that required the operation of the unit.

§ 506.38 [Reserved]

§ 506.39 Scheduled equipment outages.

(a) *Eligibility.* Section 312(b) of the Act provides for a permanent exemption to meet scheduled equipment outages. To qualify you must demonstrate to the satisfaction of ERA that:

(1) Your routine maintenance schedule does not permit, or could not be adjusted to permit, continuing production or other activity carried on at the site unless ERA grants this exemption and the reasons why;

(2) If your scheduled outages and thereby your projected use of the proposed unit exceed 21 days per year, you cannot meet your requirements by burning an alternate fuel; and

(3) The pertinent unit will be used only during those periods when other units are not in operation for reason of scheduled outage.

(b) *Evidence required in support of a petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) An explanation of why your routine maintenance schedule does not permit, or could not be adjusted to permit, continuing production or other activity carried on at the site unless ERA grants this exemption;

(2) A schedule of operation for the pertinent unit estimating the number of hours per year used and fuel consumed during the first 12 months of operation after commencement of operation;

(3) A description of the maintenance schedule for all units located at the facility specifically identifying those units at the facility which will be out of service for scheduled maintenance at times when the unit for which the exemption is required, is operating; and

(4) If your scheduled outages and thereby your projected use of the proposed unit exceed 21 days per year, documentary evidence which demonstrates that you considered the use of alternate fuels, including a description of the fuel alternatives you examined and the factors important in your decision to reject the use of alternate fuels. Such factors would include lack of alternate fuel supply, site limitations, environmental requirements, or certain state or local requirements.

(c) *Reporting requirement.* ERA will rely upon the schedule of operation of the unit submitted with the petition as the permanent schedule for exempt use. You must notify ERA in advance of any changes to this schedule.

(d) *Exercise of discretion by ERA.* ERA may refuse to grant this exemption to you if it determines that such grant would not be in the public interest or in accordance with the purposes of the Act, notwithstanding the fact that the evidence you have furnished to ERA in your exemption petition substantiates that your facility would otherwise be eligible to receive the exemption.

(e) *Emergency use.* You may apply for an emergency exemption in addition to this exemption for the same unit. You must meet the eligibility and evidence requirements of each exemption to obtain them. You must also comply with the reporting requirements of each.

§ 506.40 Installations served by certain international pipelines.

(a) *Eligibility.* Section 312(j) of the Act provides for a permanent exemption for the use of natural gas by installations served by certain international pipelines. To qualify you must demonstrate to the satisfaction of ERA that:

(1) Your primary source of natural gas is under a contract with a pipeline between the United States and Canada;

(2) The contract was signed before April 21, 1977;

(3) The natural gas would revert to Canada if you are not granted an exemption;

(4) The pipeline serves high priority users as defined in paragraph (b) below:

(5) You would suffer substantial financial penalty if the contract were cancelled and there is no available relief from the penalty; and

(6) The revenues from the transportation and sale of natural gas under your contract are essential to the economic vitality of the pipeline.

(b) For purposes of this section the term "high priority user" means any residential user of natural gas or any commercial user whose consumption of natural gas on a peak day is less than 50 MCF.

(c) *Evidence required in support of the petition.* You must include in your Fuels Decision Report at least the following evidence in order to make the demonstration required by this section:

(1) A copy of your contract with the international pipeline with the applicable sections underlined;

(2) A certification from the natural gas supplier of the pipeline that the natural gas would revert to Canada upon cancellation of the contract;

(3) A certification by the pipeline that it serves high priority users and a description of those users;

(4) An explanation of the substantial financial penalty that would be incurred;

(5) An explanation of why *force majeure* would not apply to the contract cancellation;

(6) A description of your attempt to transfer your contract as described in Section 731 of the Act; and,

(7) A decision from the Federal Energy Regulatory Commission that the revenues from the transportation and sale of natural gas under your contract are essential to the economic vitality of the pipeline.

Appendix I—Procedures for the Computation of the Real Cost of Capital

(a) The discount rate for use in determining if it is financially feasible to convert a facility from oil or gas to alternate fuel is the firm's real after-tax weighted average marginal cost of capital. This appendix outlines the procedure used to compute it.

(b) The firm's real after-tax weighted average marginal cost of capital (K) is computed with equation 1.

EQ 1

$$K = W_D \cdot \left[\frac{\hat{R}_D \cdot (1 - t)}{1 - f_D} - INF \right] + W_p \cdot \left[\frac{\hat{R}_p}{(1 - f_p)} - INF \right] + W_e \left[\frac{\hat{R}_e}{(1 - f_e)} - INF \right]$$

The terms in equation 1 are defined as follows:

W_D Fraction of existing capital structure which is debt.

W_p Fraction of existing capital structure which is preferred equity.

W_e Fraction of existing capital structure which is common equity and retained earnings.

$\hat{R}_D$ Predicted nominal cost of long term debt expressed as a fraction.

$\hat{R}_p$ Predicted nominal cost of preferred stock expressed as a fraction.

$\hat{R}_e$ Predicted nominal cost of common stock expressed as a fraction.

INF Percentage change in the GNP implicit price deflator over the past 12 months expressed as a fraction.

f_D Flotation cost of debt expressed as a fraction.

f_p Flotation cost of preferred stock expressed as a fraction.

f_e Flotation cost of common stock expressed as a fraction.

t Marginal federal income tax rate for the current year.

(c) The predicted nominal cost of debt ($\hat{R}_D$) is estimated by determining the current average yield on newly issued bonds—industrial or utility as appropriate—which have the same Moody's bond rating as the firm's most recent debt issue.

(d)(1) In the case of utilities, the predicted nominal cost of preferred stock ($\hat{R}_p$) is estimated by determining the current average yield on newly issued utility preferred stock which has the same Moody's rating as the firm's most recent preferred stock issue.

(2) In the case of industrials, who do not typically issue preferred stock, the predicted nominal cost of preferred stock ($\hat{R}_p$) is estimated by determining the current average yield on newly issued industrial bonds which have the same Moody's rating as the firm's most recent debt issue.

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(e) (1) The predicted nominal cost of common stock ($\hat{R}_e$) is computed with equation 2.

$$\text{EQ2} \qquad \hat{R}_e = \hat{R}_f + B \times \overline{R_m}$$

where

$\hat{R}_f$ = the risk free interest rate--the average of the most recent auction rates of U.S. Government 13-week Treasury Bills,

B = the "beta" coefficient--the relationship between the excess return on common stock and the excess return on the S&P 500 composite index, and

$\overline{R_m}$ = the mean excess return on the S&P 500 composite index--the mean of the difference between the return on the S&P 500 composite index and the risk free interest rate.

(2) The "beta" coefficient is computed with regression analysis techniques. The regression equation is equation 3.

$$\text{EQ3} \qquad (R_e^t - R_f^t) = A + B\,(R_m^t - R_f^t) + e_t$$

where

$$R_e^t = \frac{PRCC_t - PRCC_{t-1} + (DIVRATE_t/12)}{PRCC_{t-1}}$$

R_f^t = the risk free interest rate in month t--the average of the yields on 13-week Treasury Bills auctioned in month t,

A = a constant which should not be significantly different than zero,

$$R_m^t = \frac{V_{sp,t} - V_{sp,t-1} + D_{sp,t}}{V_{sp,t-1}}$$, and

e_t = the error in month t.

$PRCC_t$ = closing market prices of the firm's common stock at the end of month t fully adjusted for splits and stock dividends.

DIVRATE = the sum of the dividends paid in the fiscal year which contain month t.

$V_{sp,t}$ = the market value of "one share" of the S&P 500 composite index at the end of month t.

$D_{sp,t}$ = the estimated monthly income received from holding "one share" of the S&P 500 in month t.

The regression analysis is done with sixty months of data. The first month (t=1) is sixty months before the month in which the firm's current fiscal year started. The last month (t=60) is the last month of the past fiscal year.

(3) The mean excess return on the S&P 500 composite index is computed with equation 4.

$$\text{EQ4} \qquad \overline{R_m} = \frac{1}{60} \sum_{t=1}^{60} (R_m^t - R_f^t)$$

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Monday
July 23, 1979

Part IV

Department of Health, Education, and Welfare

Public Health Service

Family Planning Services; Grants for Adolescent Pregnancy Prevention and Services Projects

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Public Health Service

42 CFR Part 59

Family Planning Services; Grants for Adolescent Pregnancy Prevention and Services Projects

AGENCY: Public Health Service, HEW.

ACTION: Final rules.

SUMMARY: The Secretary of Health, Education, and Welfare is issuing rules for grants for the establishment of projects to provide needed comprehensive community services to assist in preventing unwanted initial and repeat pregnancies among adolescents and to assist pregnant adolescents and adolescent parents to obtain needed health, social, educational, and other services. The rules are needed in order to implement the grant program recently enacted by Title VI of Pub. L. 95-626.

DATE: These rules are effective on July 23, 1979.

FOR FURTHER INFORMATION CONTACT: Dr. Lulu Mae Nix, Director, Office of Adolescent Pregnancy Programs, Office of the Assistant Secretary for Health, HEW, Room 725-H, Humphrey Building, 200 Independence Avenue SW., Washington, D.C. 20201, (202) 472-9093.

SUPPLEMENTARY INFORMATION: On March 12, 1979, the Secretary proposed rules to govern grants to be made by the Secretary under Title VI of Pub. L. 95-626 (42 U.S.C. 300a-21, *et seq.*). 44 FR 13549. Title VI authorizes a program of grants to be made to public and private nonprofit entities to assist them in operating projects to provide needed comprehensive community services to (1) assist in preventing unwanted initial and repeat pregnancies among adolescents and (2) assist pregnant adolescents and adolescent parents to obtain needed medical, social, educational, and other services that will help them to become productive and indepdenent contributors to family and community life.

Although in many respects the proposed rules closely tracked the statute, they proposed more detailed requirements in the areas of fee schedules, management requirements, the requirement for consultation with parents, the definition of "adolescent", and the criteria for waiver of reduction in the grant amount. Comments were particiularly solicited with respect to these proposed policies. The Department received 122 comments on the proposed rules. Although many commented on the proposed policies in the areas described above, a number of substantive comments were made on other aspects of the propsed rules. The public comments, and the Department's responses thereto, are summarized below.

I. Definitions

A. Background

Proposed § 59.302 defined a number of terms. The definitions of "core" and "supplemental" services, "eligible grant recipient", and "Secretary" essentially repeated the statutory language, but new definitions or policies were added in the definitions of "adolescent", "adolescent parent" and "service area".

B. Comments

1. *"Adolescent" and "adolescent parent":* A number of comments urged that these definitions set the age limits at 18 rather than at 21, as proposed. They argued that the most significant social and medical problems arise with persons under 18, while those adolescents between 18 and 21 have the highest incidence of pregnancy, and thus would be likely to obtain the major share of project services.

2. *"Core" and "supplemental services":* Many comments objected to the general nature of the definitions of these terms. These comments urged that the particular services components be itemized, so that all persons served by the program would receive comparable services. A number of comments also suggested the inclusion of particular services within certain components of the "core" and "supplemental services", on the ground that the services recommended for inclusion are essential and should be included in any project funded under the program. Several comments asserted that, in view of the importance of counseling in facilitating the utilization by adolescents of other program services and in coping with their problems, counselling should be made a separate core service.

3. *"Eligible grant recipient":* Several educational associations protested that the regulations should specifically mention schools and other educational agencies as eligible grant recipients in light of their central role in dealing with adolescents.

One comment urged that this definition be narrowed to include only those agencies which could provide the core services directly.

4. *"Eligible person":* A number of comments urged redefinition of this term to include persons over 21. They argued that pregnant women who enter the program shortly before their twenty-first birthday should not lose services because of this age limit.

5. *"Network":* Several comments suggested that this term be defined, since it is not a term of art with a precise and generally understood meaning, and suggested specific definitions.

C. Response

1. *"Adolescent" and "adolescent parent":* The age limit of these definitions has not been lowered to 18 as suggested by some of the comments, as the Secretary believes that an age limit of 21, rather than 18 as suggested, is what the statute clearly contemplates. See in particular the definition of "adolescent parent" in section 602(6) of the Act, which defines such persons as parents "under the age of 21." As for the concern that persons between the ages of 18 and 21 will receive a disproportionate amount of project services, the Secretary points out that the statute (and these regulations) requires that priority in services be given to adolescents 17 and under. Any project funded under the Act, therefore, will have to demonstrate that it has designed its program so as to carry out this priority.

However, the definition of "adolescent" has been amended to include pregnant women who turn 21 during the course of their pregnancies to prevent the abrupt cessation of project services to them. See discussion under "eligible person" above.

2. *"Core" and "supplemental services":* These definitions remain unchanged, despite the recommendations that they be made more specific. The Secretary believes that further specificity in this area would limit the flexibility of individual projects to tailor the package of services to the needs of their particular service areas. However, the regulation has been changed to require grantees to specify what particular services they will provide so that the Secretary will be able to determine the adequacy of the package of services to be provided. See § 59.304(a)(2). Program guidance materials are being developed and will set forth services that should be provided as "core" or "supplemental services".

With regard to the suggestion that counselling be listed as an additional core service, the Secretary believes that counselling is already adequately covered by sections (a) through (e) and (g) through (j) of "core services" and sections (c) and (d) of "supplemental services."

3. *"Eligible grant recipient":* The Secretary has not accepted the suggestion that this definition specifically identify educational institutions and agencies as eligible grantees, since in his view such agencies are clearly eligible if able to meet the requirements of this subpart. The emphasis on the provision of medical services by grantees, objected to by several commentors, reflects the statute, which requires that various medical services be provided by grantees.

For clarity, this term has been removed in the rules below from the definitions section. Its substance now appears, however, in § 59.303.

4. *"Eligible person":* The problem raised by the comments in connection with this definition has been remedied by the change in the definition of "adolescent" discussed in paragraph 1 of this section above.

5. *"Network":* The rules below, like the proposed rules, do not define this term. Examples of permissible network arrangements will be provided in the program guidance materials which are being developed.

II. Written agreements

A. Background

The statute provides that grantees may provide services by arrangement with other providers, as well as directly. The proposed rules did not require written agreements as a basis for approval of such "linkages", but asked whether they should be required.

B. Comment

Thirty-nine comments dealt with the question of whether or not written agreements should be required; of these, almost all recommended that they be required. They argued that only thus could it be ensured that services would be provided, since the details of agreements may be difficult to work out. Thus, if the agreements are not in place when the grant is made, much of the grant period would pass before the arrangements were finalized and services were provided. It was also argued that only thus could the Secretary ascertain whether the linkage arrangements were viable and provided for adequate financial arrangements, responsibility for record-keeping and follow-up.

A few comments argued, however, that written agreements should not be required. They argued that an inflexible requirement might exclude from funding some otherwise worthwhile projects, which were unable to secure such agreements by the application deadline, despite reasonable efforts to do so.

C. Response

The Secretary agrees that written agreements are desirable, wherever feasible, but is persuaded that establishing an absolute requirement for them might preclude him from funding some otherwise worthwhile projects. Moreover, it should be noted that the Act does not permit him to establish an absolute requirement with respect to the major third-party payors, Titles XIX and XX. See section 606(a)(14). Therefore, the rules below strike what the Secretary believes is a reasonable balance between the opposing considerations voiced by the comments. First, they provide that where agreements exist, they must be provided with the application so that the Secretary can review the adquacy of the arrangements established. See § 59.304(a)(2). Second, they provide that priority will be given to projects with written agreements in place. See § 59.306(a)(3). The Secretary believes that this latter provision will provide a strong incentive for applicants to secure such arrangements wherever feasible.

III. Referral services

A. Background

The proposed rules, like the statute, provided that projects must provide extensive referral services. See sections (a), (b), (e), (f), (h), (i), and (j) of the definition of "core services." Applications were required to contain a description of how appropriate referral would be provided. See proposed § 59.304(a)(3)(ii).

B. Comment

A number of comments stressed the importance of adequate referral arrangements to the effectiveness of the projects. They pointed out that written arrangements were needed to assure promptness of referral and service and responsible procedures regarding confidentiality and transmittal of medical records. The comments stressed in particular the necessity of assuring adequate follow-up on referred cases, and recommended that specific requirements providing for this be added.

C. Response

The Secretary is persuaded by the comments stressing the need for provision for adequate follow-up, and has revised § 59.304(a)(3) accordingly. However, the Secretary is not requiring written agreements for such referral services as suggested by many of the comments, for the reasons discussed in the preceding section.

IV. Fee Schedules

A. Background

The Act contains several different requirements that relate to the fees grantees may charge for their services. Section 606(a)(17) requires grantees to have fee schedules designed to cover their reasonable costs of operation, with corresponding discounts based on ability to pay. Section 606(a)(7) requires a description of the fee schedules. Section 604(b) requires that fee schedules be based on ability to pay and take into account the difficulty adolescents face in obtaining resources to pay for services.

Proposed § 59.304(a)(5) implemented these requirements as follows: Grantees must have fee schedules designed to cover their costs of operation, with a schedule of discounts that provides for full discount to persons with annual incomes at or below the Community Services Administration (CSA) Poverty Income Guidelines and no discount to persons with incomes above twice the CSA Poverty Income Guidelines. In addition, full discounts must be provided to all eligible persons, regardless of income, (1) for pregnancy testing services, and (2) where the eligible person is unable to pay for the services and is unable to obtain financial assistance to pay for them.

B. Comment

The fee schedule provisions of the proposed rules elicited the most comment of any of the provisions. The most significant comments were as follows:

1. Many of the comments opposed imposition of specific fee schedule requirements in general and the choice of the 100%–200% of the CSA Poverty Income Guidelines as the income test in particular. It was argued that such uniform requirements would ignore local or regional differences in income levels and costs, resulting in unduly restrictive (or liberal) charges in different areas. Others argued specifically that the proposed sliding fee schedule for persons with incomes between 100 and 200% of the CSA Poverty Income Guidelines was unduly harsh, as those people (the "working poor") are least likely to have private insurance coverage and will not qualify for most governmental benefit programs.

Other comments, however, agreed with the proposed two-tier fee schedule policy, on the ground that it would promote uniformity of administration. One comment, in fact, suggested that the Secretary establish a mandatory sliding fee scale for persons with incomes between 100% and 200% of the CSA Poverty Income Guidelines.

2. Most of the comments endorsed the policy of providing pregnancy testing without charge, but a number also urged that this policy be extended to cover information, education, counselling and referral services, on the ground that those services are essential if adolescents and their families are to solve the problems associated with their pregnancies successfully.

3. Several comments objected that, it is unreasonable to require that the fee schedules cover the projects' "costs of operations", since few adolescents will have sufficient income to pay realistic fees. They pointed out that this problem is exacerbated by the requirement that projects serve so many individuals without charge.

4. Many comments stated that the two-tier fee schedule was unrealistic as applied to adolescents, because adolescents frequently do not have access to their parents' income and, in fact, may not even know what it is. A number also stated that the "unable to obtain" language of proposed § 59.304(a)(5)(ii)(C) would deter adolescents from seeking services where they were reluctant to seek financial assistance from their parents.

C. Response

1. A large number of the comments critical of the proposed range for fee schedules misunderstood the nature of the proposal. The proposal would have provided wide latitude in establishing discounts between 100 and 200 percent of CSA Income Poverty Guidelines which could be exercised to accommodate varying economic conditions prevailing in particular areas. These guidelines, as with all measures of poverty, have limitations. However, they are widely accepted and used by numerous programs of the Public Health Service, where, experience has shown, they are not restrictive.

Nevertheless, the many comments on the proposed rule have caused the Secretary to re-evaluate the appropriateness of the mandatory link of the fee schedule to the CSA Poverty Income Guidelines for this program. The unique characteristics of the population to be served by this program, together with the statutory mandate that projects have fee schedules which "take into account the difficulty adolescents face in obtaining resources to pay for services," have led the Secretary to conclude that the two-tier fee schedule approach proposed would be inappropriate, as an absolute requirement, for this program. As pointed out by many comments, adolescents frequently do not have access to their parent's income and often do not know what it is. Moreover, financial resources may vary significantly among adolescents independently of family income. The rules below thus give projects the flexibility to adjust their fee schedules to local conditions. At the same time, however, this flexibility permits projects to adopt a fee schedule such as the one proposed, if the projects desire to do so.

2. The suggestion that projects be required to provide information, education, counselling and referral services free has been accepted. See § 59.304(a)(5)(ii)(B) below.

3. The Department is retaining the requirement that the fee schedule be designed to cover the project's reasonable costs of operation, since that requirement is statutory. However, the increased flexibility of the requirements below should better enable projects to meet this requirement.

4. It was not the Department's intention in proposed § 59.304(a)(5)(ii)(C) to permit projects to force adolescents to seek financial assistance from their parents in order to obtain services. However, the comments made it clear that many placed this interpretation on that section. Accordingly, the rule below adopts "unwilling to seek" financial assistance instead of the "unable to obtain" language of the proposed rule, to accomplish the result intended by the Secretary and urged by the comments.

V. Parental Consultation

A. Background

Proposed § 59.304(a)(13) provided that, although projects were required to encourage adolescents to consult with their parents with respect to project services wherever feasible, they could not condition the provision of services on such consultation unless required by State law to do so.

B. Comment

Several comments objected to the provision that grantees could condition services on parental consultation or notification if State law required such consultation or notification. They argued that this would greatly reduce utilization of services by adolescents. One comment argued that such State laws are pre-empted by the Act, and hence that the requirement is illegal. Others were concerned that the provision would cause States to enact restrictive State laws.

C. Response

The Secretary does not agree with the comments urging elimination of the provision requiring compliance with State notification laws and has retained it unchanged. He does not believe that it is appropriate to require grantees to flout State laws and assume whatever potential civil or criminal liability might consequently attach. Moreover, he notes that there is no irreconcilable conflict between such State laws and section 606(a)(21), since the policy of that section is to "encourage" consultation with parents. Nor does he believe that it is realistic to expect that the rules will cause States to enact restrictive legislation.

VI. Abortion Counselling

A. Background

Proposed § 59.304(a)(14) provided that projects must inform pregnant adolescents of the availability of counselling "on all options" concerning their pregnancies. This section simply repeated section 606(a)(22) of the Act.

B. Comment

This provision elicited a number of comments. Some stated that this language went too far, and urged barring referrals to agencies which provided abortions or abortion counselling. A number of others, however, felt that the provision did not go far enough. They argued that grantees should be required to provide abortion counselling directly or that the regulations should at least state that abortion counselling must be provided. Some also urged that grantees should be required to pay for abortions. The latter position was urged on the ground that adolescents frequently do not have sufficient money to pay for abortions themselves.

C. Response

The rule is retained as proposed. The suggestions that the Secretary bar referrals for abortion counselling or pay for abortions are rejected as inconsistent with the statute. See sections 606(a)(22) and 608 of the Act. The Secretary believes that the statutory language, requiring mention of the availability of all options, is explicit enough; clearly, a grantee could not fail to make known the availability of abortion counselling without violating this requirement. He notes, moreover, that in making grants under this subpart he will endeavor to ascertain that applicants have adequate arrangements for ensuring the availability of such counselling. With respect to the suggestion that grantees be required to provide such counselling directly, he notes that since the statute provides that they may provide counselling "through a referral agreement", he has no authority to impose such a restriction.

VII. Standards for Services

A. Background

The proposed rules required only that project personnel meet all applicable legal requirements for practice of their professions. See proposed § 59.304(a)(16).

B. Comment

A few comments pointed out that the projects themselves should, in addition to the above requirement, be required to meet any legal requirements applicable to them, such as licensure. The majority of the comments on this issue, however, urged that a requirement be added that projects must meet the highest standards for quality of care. Several of these comments suggested that the same standards approved by the Department in other programs (particularly under Title X of the Public Health Service Act and Title V of the Social Security Act) be adopted for services provided by projects under this subpart.

C. Response

The Secretary is persuaded by these comments, and has revised the rules to require applicants to describe the standards of care to be provided. Program guidance materials will include standards of care which will be consistent with those in use under Titles V and X and other appropriate HEW programs. See §§ 59.304(a)(16) and (17).

VI. Management Requirements

A. Background

The proposed rules contained a number of provisions relating to the management of projects by grantees including requirements for data gathering, financial systems, record-keeping, and utilization review. See proposed §§ 59.304(a) (9), (10), (11) and 59.305(b).

B. Comments

The comments on these sections focused on the need to gather adequate data in order to evaluate the overall impact of the projects. A number of suggestions were made as to specific data that should be collected.

C. Response

The Secretary believes that § 59.304(a)(11) and § 59.305(b) give him sufficient authority to require adequate data. Further, he does not consider it advisable to limit his flexibility by specifying in these rules exactly what items of data should be collected by grantees. However, the required reports required under § 59.305(b) have been amplified to include a reference to the uniform data system to be developed.

In addition to the foregoing, the Secretary has made several technical and editorial changes in the rules below. This regulation has been reviewed under Executive Order 12044 and it has been determined that a Regulatory Analysis is not needed.

In view of the foregoing, the Assistant Secretary for Health, with the approval of the Secretary of Health, Education, and Welfare, hereby adds a new subpart D to Part 59 of Title 42, Code of Federal Regulations, as set forth below.

Dated: July 5, 1979.

Julius B. Richmond,

Assistant Secretary for Health.

Approved: July 11, 1979.

Joseph A. Califano, Jr.,

Secretary.

A new Subpart D is added to 42 Code of Federal Regulations, Part 59, to read as follows:

Subpart D—Grants for Adolescent Pregnancy Prevention and Services Projects

Authority: Sec. 215, Public Health Service Act, 42 U.S.C. 216, 58 Stat. 690; Title VI, Pub. L. 95-626, 42 U.S.C. 300a-21, et seq., 92 Stat. 3595, et seq.

§ 59.301 To whom do these regulations apply?

The regulations of this subpart apply to all grants for adolescent pregnancy services and prevention projects authorized under Section 603 of Title VI of Public Law 95-626 (42 U.S.C. 300a-21, et seq.).

§ 59.302 How are the terms in these regulations defined?

As used in this subpart, the term:

"Act" means Title VI of Public Law 95-626 (42 U.S.C. 300a-21, et seq.).

"Adolescent" means a person whose age is between the onset of puberty and the age of 21, except that a pregnant adolescent who turns 21 during the course of her pregnancy will be considered to be an adolescent for purposes of this subpart until the pregnancy ends.

"Adolescent parent" means a parent or parent-to-be under the age of 21.

"Core services" means the following which shall be provided by all grantees:

(a) Pregnancy testing (including menstrual history, pelvic examination, and laboratory test for pregnancy detection), maternity counseling, and referral for related services;

(b) Family planning services, except that such services for nonpregnant adolescents shall be limited to family planning counseling and referral for family planning services unless suitable and appropriate family planning services are not otherwise available in the community;

(c) Primary and preventive health services, including pre- and post-natal care;

(d) Nutrition information and counseling;

(e) Referral for screening and treatment of venereal disease;

(f) Referral to appropriate pediatric care;

(g) Educational services in sexuality and family life including sex education and family planning information;

(h) Referral to appropriate educational and vocational services;

(i) Adoption counseling and referral services; and

(j) Referral to other appropriate health services.

"Eligible person" means—

(a) With regard to the provision of all necessary core services and such necessary supplemental services as may be available, a pregnant adolescent or an adolescent parent; or

(b) With respect to the provision of the services described in paragraphs (a), (b), and (g) of the definition of "core services" and referral to such other services as may be appropriate, a nonpregnant adolescent.

"Nonprofit", as applied to any private agency, institution or organization, means one which is a corporation or association, or is owned and operated by one or more corporations or associations, no part of the net earnings of which benefits, or may lawfully benefit, any private shareholder or individual.

"Secretary" means the Secretary of the Health, Education, and Welfare or any other officer or employee of the Department of Health, Education, and Welfare to whom the authority involved has been delegated.

"Service area" means the geographic area served (or to be served) by a project supported under this subpart.

"Supplemental services" means those services which may be provided and are—

(a) Child care sufficient to enable an adolescent mother to continue her education or to enter into employment;

(b) Consumer education and homemaking;

(c) Counseling for extended family members of the eligible person;

(d) Transportation; and

(e) Such other services, consistent with the purposes of the Act, as the applicant considers appropriate and as the Secretary approves in the grant award, and which will, in his judgment, enhance the effectiveness of the core services provided to eligible persons.

§ 59.303 Who is eligible to apply for a grant under this subpart?

A grant under this subpart may be awarded only to a public or nonprofit private organization or agency which demonstrates, to the satisfaction of the Secretary, the capability of providing in a single setting all core services or the capability of creating a network of providers through which all core services would be provided.

§ 59.304 How is application made for a grant under this subpart?

(a) An application for a grant under this subpart shall be submitted at such time and in such form and manner as the Secretary may prescribe and shall contain—

(1) The following information, using data and methods satisfactory to the Secretary, for the applicant's service area:

(i) An identification of the incidence of adolescent pregnancy and related problems;

(ii) A description of the economic conditions and income levels;

(iii) A description of existing pregnancy prevention and pregnancy-related services (including family life and sex education), including where, how, by whom and to whom they are provided, and the extent to which they are available and coordinated; and

(iv) A description of the major unmet needs for services for adolescents at risk of initial or repeat pregnancies, the estimated number of adolescents currently served in the area, and the estimated number of adolescents not being served in the area.

(2) A description of how all the core services and any supplemental services which the applicant proposes to provide will be provided in the project (including what particular services will be provided under each of the core services and a timetable for their provision), to whom they will be provided, how they will be coordinated, integrated, and linked with other related programs (supported by any written agreements or other evidence of arrangements between the applicant, governmental, other third-party payors, and other providers of services) and services and the source or sources of funding of the such services.

(3) A description, in such detail as the Secretary may require, of—

(i) How adolescents needing services other than those provided directly by the grantee (such as school education, social services, medicaid, public assistance, employment services, child care services for adolescent parents, and other city, county, and State programs related to adolescent pregnancy) will be identified and reached; and

(ii) How access and appropriate referral to those services will be provided, including a description of the plan to coordinate those services with the project's activities and arrangements for appropriate follow-up of persons referred (supported by any written agreements or other evidence of arrangements between the applicant, governmental, other third-party payors, and other providers of services).

(4) A description of the results expected from the provision of services and activities, and the procedures to be used for evaluating those results.

(5)(i) Assurance that the applicant has prepared a schedule of fees or payments for the provision of its services which is designed to cover its reasonable costs of operation and a corresponding schedule of discounts to be applied to the payment of such fees or payments ("fee schedule"). The discounts must be adjusted on the basis of the ability to pay of the eligible person or his or her parents or legal guardians, as applicable.

(ii) A description of the fee schedule, together with the method by which it was derived. The fee schedule must provide for:

(A) A full discount to eligible persons and their parents or legal guardians, regardless of income, for pregnancy testing services;

(B) A full discount to eligible persons and their parents or legal guardians, regardless of income, for counseling, education, information, and referral services provided by the project; and

(C) A full discount to eligible persons, regardless of the annual incomes of their parents or legal guardians, where the eligible persons are unable to pay for services without financial assistance from their parents or legal guardians and are unwilling to seek that financial assistance for the services.

(6) Assurances that the applicant has made and will continue to make every reasonable effort—

(i) To secure from eligible persons and their parents or legal guardians payment for services in accordance with the requirements of subparagraph (5) of this paragraph;

(ii) To collect reimbursement for its cost of providing services on the basis of full amount of fees and payments for such services without application of any discount, except as provided in subparagraph (5) of this paragraph; and

(iii) To collect reimbursement for its costs in providing services to persons who are entitled—

(A) To benefits under the program for maternal and child health services under Title V of the Social Security Act (42 U.S.C. 701 et seq.);

(B) To medical assistance under the Medicaid program (Title XIX of the Social Security Act, 42 U.S.C. 1396, et seq.);

(C) To services under a State plan for social services approved under Title XX of the Social Security Act (42 U.S.C. 1397, et seq.); or

(D) To assistance for medical expenses under any other public assistance program or private health insurance program.

(7) Assurances that fees collected by the applicant for services rendered shall be used by the applicant to further the purpose of the project.

(8) Assurances that the applicant—

(i) Has or will have a contractual or other arrangement with the agency or agencies of the State in which it provides services which administer or supervise the administration of the State plan approved under Titles XIX and XX of the Social Security Act for the payment of all or a part of the applicant's costs in providing services to persons who are eligible for medical assistance or social services under such plans; or

(ii) Has made or will make every reasonable effort to enter into such an arrangement.

(9) Assurance that the applicant will have an ongoing program to assure quality in the provision of its services. The quality assurance program must provide for:

(i) Organizational arrangements, including a focus of responsibility, to support the quality assurance program and the provision of high quality care and services; and

(ii) Periodic assessment of the appropriateness of the utilization of services and the quality of services provided or proposed to be provided to persons served. Those assessments shall:

(A) Be conducted by licensed health professionals or others, as appropriate;

(B) Be based on the systematic collection and evaluation of client records; and

(C) Identify and document the necessity for change in the provision of services by the project and result in the institution of such change where indicated.

(10) Assurances that the applicant will have a system for maintaining the confidentiality of patient records in accordance with the requirements of § 59.310(b) of this subpart.

(11) Assurances that—

(i) The applicant will demonstrate its financial responsibility by developing management and control systems which are in accordance with sound financial management procedures, including the provision for an audit on an annual basis (unless waived for cause by the Secretary) by an independent certified public accountant or a public accountant licensed prior to December 31, 1970, to determine, at a minimum, the fiscal integrity of grant financial transactions and reports, and compliance with the regulations of this part and the terms and conditions of the grant.

(ii) The applicant will establish basic statistical data, cost accounting, management information, and reporting or monitoring systems which will enable it to provide such statistics and other information as the Secretary may reasonably require relating to the projects costs of operation, patterns of utilization and the availability, acceptability and accessibility of its services and to make such reports to the Secretary in a timely manner with such frequency as the Secretary may reasonably require.

(12) Assurances that the acceptance by any individual of family planning services or family planning or population growth information (including educational materials) provided by the project shall be voluntary and shall not be a prerequisite to eligibility for or receipt of any other service furnished by the applicant.

(13) Assurances that persons who are unemancipated minors under State law who request services from the applicant will be encouraged, whenever feasible, to consult with their parents or legal guardians with respect to such services. An applicant may not condition the provision of services on such consultation or on parental notification, unless State law requires it to do so.

(14) Assurances that each pregnant adolescent receiving services will be informed of the availability of counseling (either by the entity providing core services or through a referral agreement with another entity which provides such counseling) on all options regarding her pregnancy.

(15) Assurances that primary emphasis for services paid for with funds under the project shall be given to pregnant adolescents and adolescent parents 17 and under who are not able to obtain needed assistance through other means.

(16) A description of the proposed staffing pattern which will be employed to carry out the project, including evidence that project professional and other staff meet all applicable licensure, certification or other legal requirements for the practice of their professions and evidence that all applicable legal requirements (such as licensure) necessary to carry out the project have been met.

(17) A description of the standards of care for all services provided. Grantees shall provide services in accordance with standards of care that may be prescribed by the Secretary.

(18) A budget including required matching funds and a fiscal plan for assuring effective utilization of grant funds) and a justification of the amount of funds requested.

(19) A description of the applicant's capacity to continue services as Federal funds decrease and in the absence of Federal assistance.

(20) Assurances that the applicant will make maximum use of funds available under the program of project grants for family planning services under Title X of the Public Health Service Act.

(21) Assurance that funds received under this Act shall not supplant funds received from any other Federal, State, or local program or any private sources of funds.

(22) A summary of the views of public agencies, providers of services, and the general public in the service area, of the proposed use of the funds provided and a description of procedures used to obtain those views. In the case of applicants who propose to coordinate services administered by a State, the written comments of the appropriate State officials responsible for such services shall also be included.

(23) Evidence that the requirements of Part I of Office of Management and Budget Circular No. A-95 have been satisfied.

(b) The application shall be executed by an individual authorized to act for the applicant and to assume for the applicant the obligations imposed by the statute, the applicable regulations and any additional conditions of the grant.

§ 59.305 What requirements must a project funded under this subpart meet?

A project funded under this subpart shall:

(a) As appropriate, and in accordance with the assurances in the application, the grant award and applicable law, provide, supplement or improve the quality of core and supplemental services to eligible persons in its service area.

(b) Make such reports concerning its use of Federal funds as the Secretary may require. Reports must include the impact the project has had within its service area on reducing the rate of first and repeat pregnancies among adolescents, and the effect on factors usually associated with welfare dependency and any data which the Secretary requires as part of a comprehensive uniform management data system.

(c) Operate in a manner such that no person shall be denied service by reason of his or her inability to pay therefore, *except that,* a charge for the provision of service will be made to the extent that a third party (including a Government agency) is authorized or is under legal obligation to pay that charge.

(d) Where a grantee under this subpart is a State using funds provided under this subpart to improve the delivery of pregnancy-prevention and pregnancy-related services throughout the State, it shall coordinate its activities with the programs of local grantees, if any, under this subpart.

§ 59.306 What criteria has HEW established for deciding which applications for grants under this subpart to fund?

Within the limit of funds available for such purposes, the Secretary may award grants to eligible grant recipients whom he determines have submitted applications which meet the requirements of § 59.304 for projects which will help communities provide core and supplemental services in easily accessible locations; assure a continuity of services and appropriate assistance, coordinate, integrate, and establish linkages among such services, and best promote the purposes of the Act. No application will be approved unless the Secretary is satisfied that core services will be available through the applicant within a reasonable time after the grant is received. In approving applications the Secretary will:

(a) Give priority to applicants who:

(1) Serve an area where there is a high incidence of adolescent pregnancy;

(2) Serve an area where the incidence of low-income families is high and where the availability of pregnancy-related services is low;

(3) Show evidence of having the ability to bring together a wide range of needed core and, as appropriate, supplemental services in comprehensive, single-site projects, or to establish a well-integrated network of such services (appropriate for the target population and geographic area to be served including the special needs of rural areas) for adolescents at risk of initial or repeat pregnancies. Written agreements with other providers of services will be considered to be the best evidence of ability to establish a network of services and of the ability to ensure adequate follow-up of referral cases.

(4) Will utilize, to the maximum extent feasible, existing available programs and facilities such as neighborhood and primary health care centers, family planning clinics, children and youth centers, maternal and infant health centers, regional rural health facilities, school and other educational programs, mental health programs, nutrition programs, recreation programs, and other ongoing pregnancy prevention and pregnancy-related services;

(5) Make use, to the maximum extent feasible, of other Federal, State, and local funds, programs, contributions, and other third-party reimbursements;

(6) Can demonstrate a community commitment to the program by making available to the project non-Federal funds personnel, and facilities; and

(7) Have involved the community to be served, including public and private agencies, adolescents, and families, in the planning and implementation of the project.

(b) Take into account:

(1) The reasonableness of the budget and the soundness of the fiscal plan for assuring effective utilization of grant funds;

(2) The potential effectiveness of the proposed project in carrying out the statutory purposes;

(3) The adequacy of the facilities and other resources available to the applicant;

(4) The professional, administrative, and managerial capability of the applicant; and

(5) The total amount of funds available for implementing the overall program.

§ 59.307 How is the amount of the grant decided?

(a) The Secretary will determine the amount of the grant based on factors such as the incidence of adolescent pregnancy in the service area, the adequacy of pregnancy prevention and pregnancy-related services in the service area, as well as his estimate of the sum necessary for the proper performance of the project. In determining the amount of the grant, the Secretary will consider the special needs of rural areas and, to the maximum extent practicable, will distribute funds in consideration of the relative number of adolescents in those areas who are in need of services.

(b) A grant award may not exceed 70% of the costs of a project for the first year of the project and a grant award for the second year of the project may not exceed the amount awarded in the first year or 70% of project costs. In each year succeeding the second year of the project, the amount of funds granted under this subpart shall decrease by no less than 10% of the amount of the grant under this subpart in the preceding year. The Secretary may waive this reduction in the Federal grant in any year when in his judgment such limitation will result in discontinuation of essential services and the grantee has demonstrated a substantial likelihood that it will be able to provide core and supplemental services without funds granted under this subpart by the end of the project period.

(c) A grantee may not receive funds for a period in excess of five years.

§ 59.308 What is the period for which a grant will be awarded?

(a) The Notice of Grant Award specifies how long HEW intends to support the project without requiring the project to recompete for funds. This period, called the project period, will not exceed 5 years.

(b) Generally the grant will initially be funded for 1 year, and subsequent continuation awards will also be funded for 1 year at a time. A grantee must submit a separate application to have the support continued for each subsequent year. Continuation awards within the project period will be made provided required reports are not delinquent, funds are available, the grantee has made satisfactory progress, the grantee's management practices provide adequate stewardship of Federal funds, and HEW determines that continued funding is in the best interest of the Government.

(c) Neither the approval of any application nor the award of any grant commits or obligates the United States in any way to make any additional, supplemental, continuation, or other award with respect to any approved application or portion of an approved application.

§ 59.309 For what purposes may grant funds be used?

(a) Grant funds awarded under this subpart may be used by grantees only to meet the costs of—

(1) Providing core services to eligible persons;

(2) Coordinating, integrating, and providing linkages among providers of core, supplemental, and other services for eligible persons in furtherance of the purposes of the Act;

(3) Providing supplemental services where such services are not adequate or not available to eligible persons in the community and which are essential to the care of pregnant adolescents and to the prevention of adolescent pregnancy;

(4) Planning for the administration, coordination, or both, of pregnancy prevention and pregnancy-related services for adolescents, including family life and sex education, which will further the objectives of the Act; and

(5) Fulfilling the assurances required for grant approval by § 59.304 of this subpart.

(b) Grant funds awarded under this subpart may not be used to pay for the performance of abortions.

§ 59.310 What additional information should an applicant for a grant under this subpart have?

(a) *Applicability of department-wide regulations.* Attention is drawn to the following HEW department-wide regulations which apply to grants under this subpart:

(1) 45 CFR Part 19—Limitations on Payment or Reimbursement for Drugs.

(2) 45 CFR Part 74—Administration of Grants.

(3) 45 CFR part 80—Nondiscrimination under programs receiving Federal assistance through the Department of Health, Education, and Welfare's implementation of Title VI of the Civil Rights Act of 1964.

(4) 45 CFR Part 84—Nondiscrimination on the basis of handicap in programs and activities receiving or benefiting from Federal financial assistance.

(b) *Confidentiality.* All information as to personal facts and circumstances obtained by the project staff about recipients of services shall be held confidential. This information shall not be disclosed without the individual's consent except as may be required by law or as may be necessary to provide service to the individual or to provide for audits by the Secretary with appropriate safeguards for confidentiality of patient records. Otherwise, information may be disclosed only in summary, statistical, or other form which does not identify particular individuals.

(c) *Additional conditions.* The Secretary may with respect to any grant impose additional conditions prior to or at the time of any award when in his judgment additional conditions are necessary to assure or protect advancement of the approved program, the interests of public health, or the proper use of grant funds.

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Monday
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Part V

Department of Transportation

Federal Highway Administration

Directional and Informational Sign Standards and Systems; Availability of Report

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

[23 CFR Parts 750 and 751]

[FHWA Docket Nos. 76-12 and 79-10]

Directional and Informational Sign Standards and Systems; Availability of Report

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice of availability of report of task force to restudy directional and informational signing; transfer of docket materials.

SUMMARY: Pursuant to section 122(b) of the Federal-Aid Highway Act of 1976, 23 U.S.C. section 131(q)(1), the Federal Highway Administration (FHWA) formed a task force to consider directional and informational signing. The task force began its work by issuing an Advance Notice of Proposed Rulemaking on this subject on October 26, 1976, at 41 FR 46877 (FHWA Docket No. 76-12). The task force has submitted its final report to the Federal Highway Administrator. This notice announces the availability of that report. The report will be considered in the course of the reassessment of the Highway Beautification Program announced in an Advance Notice of Proposed Rulemaking published on April 30, 1979, at 44 FR 25388 (FHWA Docket No. 79-10). The report does not represent the final views of the FHWA on the subject of directional and informational signing. Although comments are not being solicited on the report itself, the FHWA anticipates that the report may provide useful information to those wishing to comment on the motorist information systems as they relate to the program reassessment. Comments previously submitted to Docket No. 76-12 are being transferred to Docket No. 79-10 to be considered in conjunction with comments submitted as a result of this Notice as part of the broader rulemaking proceeding.

DATES: Comments must be received on or before September 21, 1979.

ADDRESS: Submit written comments, preferably in triplicate, to FHWA Docket No. 79-10, Federal Highway Administration, Room 4205, HCC-10, 400-7th Street, SW, Washington, D.C. 20590. All comments received will be available for examination at the above address between 7:45 a.m. and 4:15 p.m. ET, Monday through Friday. Those desiring notification of receipt of comments must include a self-addressed stamped postcard.

FOR FURTHER INFORMATION CONTACT: Dr. Ross D. Netherton, Chairman, Task Force on Directional and Informational Signing, Office of Research, HRS-41, telephone number (202) 426-9710; Mr. Richard W. Moeller, Chief, Junkyard and Outdoor Advertising Branch, telephone number (202) 245-0021, or Mr. Edward Kussy, Deputy Assistant Chief Counsel for Right-of-Way and Environmental Law, telephone number (202) 426-0791. Office hours are 7:45 a.m. to 4:15 p.m., ET, Monday through Friday.

SUPPLEMENTARY INFORMATION: In 1978, the Congress directed the Secretary of Transportation to restudy the national standards for signs authorized by 23 U.S.C. 131(c)(1) and 131(f). In response to this charge, the FHWA formed an in-house interdisciplinary task force to consider existing standards. The task force soon determined that it was necessary to consider all motorist information systems to truly address the scope of the issues present. This was reflected in the Advance Notice of Proposed Rulemaking published at 41 FR 46877, October 26, 1976, with which the task force initiated its inquiry. A considerable number of comments were received in response to that Advance Notice and were considered by the task force. Further, the services of three private consultants were retained to provide additional research information.

The task force has now submitted its final report and recommendations to the Federal Highway Administration. The rulemaking process on this subject is not yet finalized, and the analysis and disposition of comments received is not set forth in this Notice of Availability. However, because the reassessment of the highway beautification program announced on April 30, 1979, set forth at 44 FR 25388, addresses the question of motorist information systems in considerable detail, it was determined that this study should be considered in that reassessment. The FHWA will make its final evaluation regarding motorist information systems after the reassessment effort is completed and as part of that reassessment. Accordingly, materials in FHWA Docket 76-12 will be transferred to FHWA Docket 79-10 and considered in the context of that rulemaking proceeding.

Copies of the task force report are available upon request at the address set forth above.

A summary of the report follows:

Purpose and Scope

From its first appearance in Federal-aid highway legislation, the program to regulate outdoor advertising in roadside areas created concern about its effect on the ability of motorists to obtain information about goods, services, and facilities needed during travel. Efforts of Congress, the Federal Highway Administration (FHWA), and the States, through their compliance laws, to assure the adequacy of information have taken three forms. First, not all roadside advertising signs are prohibited. A certain amount of outdoor advertising is authorized to remain in specified types of roadside areas. Second, States are authorized to provide, with participation of Federal-aid funds, various types of official service signing giving specific information in the interest of the traveling public, and to provide other information facilities and services. Third, various requirements have been attached to procedures for removal of nonconforming advertising signs to delay their removal until adequate alternative information sources and services are provided.

Federal law and policy have not mandated any uniform program or timetable for establishing effective alternative information systems, and they have recognized the need for flexibility in accommodating State and regional patterns of travel and economic development. State-by-State, however, development of adequate alternatives to roadside billboards as sources of motorist services information has been uneven, both in its timing and its extent. Also, a cyclical relationship has tended to develop between these alternative information sources and the removal of nonconforming signs. The lack of effective information alternatives deters removal of nonconforming advertising signs, and delay in removal of nonconforming signs reduces incentives to provide alternative information systems. Based on past experience, there is a need for greater Federal encouragement to establish motorist information systems and for private industry to participate in their development.

Accordingly, in the Federal-aid Highway Act of 1976, Congress specifically emphasized the need for progress in developing facilities, services, and programs for motorist information by the following directive to the Secretary of Transportation:

"During the implementation of State laws enacted to comply with this section, the Secretary shall encourage and assist the States to develop sign controls and programs which will assure that necessary directional information about facilities providing goods and services in the interest of the traveling public will continue to be available to motorists. To this end the Secretary shall restudy and revise as appropriate existing standards authorized under subsection 11(c)(1) and 131(f) to develop signs which are functional and esthetically compatible with their surroundings. He shall employ the resources of other Federal departments and agencies, including the National Endowment for the Arts, and employ maximum participation of private industry in the development of standards and systems of signs developed for those purposes."

The National Standards referred to above have been codified as 23 CFR Part 750, Subpart B and 23 CFR Part 655, Subpart C. Essentially these two standards relate to:

- Installation, within areas subject to control of outdoor advertising, of certain limited directional signing for public places owned or operated by Federal, State, or local governments or their agencies; publicly or privately owned natural phenomena, historical, cultural, scientific, educational, and religious sites, and areas of natural scenic beauty, or naturally suited for outdoor recreation deemed to be in the interest of the traveling public.
- Installation, within the rights-of-way of the Federal-aid primary and Interstate Systems, of a limited number of signs showing the business identification of and directional information for facilities providing gas, food, lodging, or campgrounds.

The legislative history of the Highway Beautification Act indicates that these standards were intended to be part of a comprehensive coordinated system of facilities and services addressing the needs of motorists for information regarding goods, services, and facilities desired during travel on Interstate and Federal-aid primary highways where commercial outdoor advertising is subject to control. This system was designed with recognition by Congress that the motorist's needs for information during travel are comprehensive, and that motorists deal with them by coordinating the full range of information sources and communication techniques available to them. This viewpoint is fundamental to the restudy, and the national standards specified by Congress have been evaluated as parts of a comprehensive and coordinated system—not as separate measures operating independently.

Similarly, where deficiencies in the presently authorized information system are identifed, the options for correcting them should be considered in terms of how they can perform the particular function that is needed in coordination with the system's other components.

This report is the result of a study undertaken by a task force established by the Federal Highway Administrator pursuant to section 122(b) of the Federal-aid Highway Act of 1976. The Advance Notice of Proposed Rulemaking referred to above was designed to provide an opportunity for industry, governmental agenies, and professional and other groups to make their views known.

The task force reached the following conclusions and recommendations:

Conclusions

1. Recognizing that control of outdoor advertising removes some of the sources of information that the traveling public traditionally has relied on, Congress, in the Highway Beautification Act, authorized development of other sources of information to assure that motorists can obtain information about facilities offering goods and services needed during highway travel.

2. The present legal authority permits States flexibility in designing information systems that meet their particular needs and circumstances. If this authority was fully used all States could have systems that adequately provide the minimum essential information about goods, services, facilities and attractions of interest to the traveling public.

3. To date, for a variety of reasons, State initiative in developing comprehensive information systems has been spotty. Federal support of information system development programs has tended to be permissive rather than aggressive. Incentive for private sector initiative in development of alternative information facilities has been reduced because of slowness in removal of existing nonconforming billboards.

4. The public interest in providing a safe, efficient, economical and convenient highway system, as well as congressional mandates, require that public highway agencies assume responsbility for assuring that essential information needs of the traveling public regarding goods, services, facilities and attractions relating to highway travel are adequate met.

5. While a variety of media and techniques are available for States to use in designing information systems suitable for their needs and circumstances, the adequacy of any system to meet minimum essential needs depends on it being:

Comprehensive, with coverage of all major information functions involved in trip planning and direction-finding.

Coordinated, with the selected media and techniques producing a uniform level of information service.

Cooperative, through effective working arrangements among State highway agencies, other State and local agencies concerned with travel and economic development.

In addition, it is desirable that motorist travel information systems be *incremental,* so their availability, convenience and effectiveness may be increased, and users may choose the level of information they desire and are willing to make the effort to obtain.

6. The policy of user-beneficiary responsibility for financing the highway system, declared by Congress in the Federal-aid Highway Act of 1956, is applicable to programs for assuring adequate motorist travel information services, and can provide a basis for broadening the resources available to State and Federal highway agencies in developing or expanding their travel information systems.

Recommendations

1. Regarding the National Standards for Directional and Official Signs, no revisions are justified at this time.

2. Regarding the National Standards for Signs Giving Specific Information in the Interest of the Traveling Public, revised standards issued February 9, 1979, are adequate to fully implement existing legislative authority.

3. Regarding options for achieving general program goals, it is recommended that each State be required to establish a comprehensive coordinated system for providing information about goods, services, facilities and significant travel attractions of interest to the traveling public. While this requirement does not mandate any specific or exclusive set of measures, it shall be sufficient to meet the minimum essential information needs of the traveling public, and may be incremental so as to provide more fully for the availability, convenience and effectiveness of the system.

This option is recommended over the following other options that were considered but not recommended for the reasons stated:

a. A "no change" option, relying entirely on the present law and level of program commitment. Almost fifteen years of effort under this program has failed to achieve adequate results nationwide.

b. The requirement that each State establish a basic information system composed of certain specified types of signing and facilities or their equivalent. Although this would result in a nationwide commitment of upgrading information services, it is considered desirable that States have maximum flexibility in designing systems that fit their particular needs and circumstances.

c. Repeal of Federal penalties for noncompliance with Federal standards, and reliance on State initiative to use existing authority for development of adequate travel information systems. This option offers no assurance of a uniform or adequate level of information services nationwide.

d. Continuation of present Federal requirements for control of outdoor advertising and provision of alternative information systems only for the Interstate System, and provision of financial incentives for States to control outdoor advertising and provide alternative information systems for non-Interstate Federal-aid primary highways. While this option might permit concentration of program effort where information needs actually are greatest, more study is needed to determine its impact and administrative implications.

4. Regarding specific options available to States for improving the effectiveness and coverage of motorist travel information systems, the following are recommended:

a. Authorization of additional information on standardized general service signs, both for general application and for the particular needs of bypassed communities.

b. Modification of current limitations on official destination signing to provide directional information for major travel attractions and recreations areas.

c. Increased use of existing authority for signing to provide busniess and brand identification of establishments offering travel-related services, and directional information for such establishments.

d. Increased use of existing authority for establishment of manned and unmanned facilities in safety rest areas to provide comprehensive information about local and reginal motorist services, attractions, and other matters of interest to the traveling public, together with directional information.

e. Authorization of the use of Federal-aid funds for a greater range of official publications giving travel and services information.

f. Authorization for expanded information programming for Highway Advisory Radio and for Citizens Band radio monitoring relating to motorist services and travel information needs.

In addition to the foregoing options, the following other suggested methods for providing information about motorist services and travel attractions were considered but were not recommended for the reasons stated in each case:

g. Expansion of the scope of "directional signing" under 23 U.S.C. § 131(c)(1) to authorize signs for businesses offering food, fuel, lodging, campgrounds and automotive services, and major travel attractions. This option is not recommended because it is inconsistent with the legislative purpose of § 131(c)(1), and other available methods offer better prospects of performing the information function involved.

h. Authorization of the establishment of roadside turnout areas for display of outdoor advertising consistent with the site's environmental quality. This option is not recommended because possible difficulties with safety, maintenance, and capacity are considered to outweigh possible benefits.

i. Authorization of the establishment of areas adjacent to the right-of-way for controlled display of outdoor advertising giving directional information to services and travel attractions. This option is not recommended because other options offer better prospects of providing such directional information with less adverse impact on the visual environment of the highway

5. Regarding options for improving the planning, coordination and operation of motorist travel information system, the following actions are recommended:

a. Assumption by each State highway agency of organizational responsibility for development, implementation and administration of a comprehensive motorist travel information system, and designation of responsibility for appropriate action either by the highway agency directly, or with assistance of special bodies representing other interested public agencies and private sector organizations.

b. Establishment of a national-level organization to advise on travel information needs and information system development.

c. Encourage use of contractual arrangements with private enterprise and public agencies to cooperate with highway agencies in providing needed motorist travel information services.

d. Establishment of adequate and continuing funding for development of national and statewide motorist travel information systems.

e. Establishment of major emphasis programs for research and development and demonstration projects aimed at improving the functional and cost effectiveness of motorist travel information systems.

This report is being prepared under the authority set forth in 23 U.S.C. sections 131, 315 and 319, and 49 CFR 1.48(b).

Issued on: July 17, 1979.

John S. Hassell, Jr.,

Deputy Administrator.

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	"Dial-a-Reg" (recorded summary of highlighted documents appearing in next day's issue):
202-523-5022	Washington, D.C.
312-663-0884	Chicago, Ill.
213-688-6694	Los Angeles, Calif.
202-523-3187	Scheduling of documents for publication
523-5240	Photo copies of documents appearing in the Federal Register
523-5237	Corrections
523-5215	Public Inspection Desk
523-5227	Finding Aids
523-5235	Public Briefings: "How To Use the Federal Register."

Code of Federal Regulations (CFR):

523-3419	
523-3517	
523-5227	Finding Aids

Presidential Documents:

523-5233	Executive Orders and Proclamations
523-5235	Public Papers of the Presidents, and Weekly Compilation of Presidential Documents

Public Laws:

523-5266 -5282	Public Law Numbers and Dates, Slip Laws, U.S. Statutes at Large, and Index
275-3030	Slip Law Orders (GPO)

Other Publications and Services:

523-5239	TTY for the Deaf
523-5230	U.S. Government Manual
523-3408	Automation
523-4534	Special Projects

FEDERAL REGISTER PAGES AND DATES, JULY

CFR PARTS AFFECTED DURING JULY

At the end of each month, the Office of the Federal Register publishes separately a list of CFR Sections Affected (LSA), which lists parts and sections affected by documents published since the revision date of each title.

AGENCY PUBLICATION ON ASSIGNED DAYS OF THE WEEK

The following agencies have agreed to publish all documents on two assigned days of the week (Monday/Thursday or Tuesday/Friday).

This is a voluntary program. (See OFR NOTICE FR 32914, August 6, 1976.)

Monday	Tuesday	Wednesday	Thursday	Friday
DOT/SECRETARY*	USDA/ASCS		DOT/SECRETARY*	USDA/ASCS
DOT/COAST GUARD	USDA/APHIS		DOT/COAST GUARD	USDA/APHIS
DOT/FAA	USDA/FNS		DOT/FAA	USDA/FNS
DOT/FHWA	USDA/FSQS		DOT/FHWA	USDA/FSQS
DOT/FRA	USDA/REA		DOT/FRA	USDA/REA
DOT/NHTSA	MSPB/OPM		DOT/NHTSA	MSPB/OPM
DOT/RSPA	LABOR		DOT/RSPA	LABOR
DOT/SLS	HEW/FDA		DOT/SLS	HEW/FDA
DOT/UMTA			DOT/UMTA	
CSA			CSA	

Documents normally scheduled for publication on a day that will be a Federal holiday will be published the next work day following the holiday.

Comments on this program are still invited. Comments should be submitted to the Day-of-the-Week Program Coordinator, Office of the Federal Register, National Archives and Records Service, General Services Administration, Washington, D.C. 20408

***NOTE: As of July 2, 1979, all agencies in the Department of Transportation, will publish on the Monday/Thursday schedule.**

REMINDERS

The items in this list were editorially compiled as an aid to Federal Register users. Inclusion or exclusion from this list has no legal significance. Since this list is intended as a reminder, it does not include effective dates that occur within 14 days of publication.

Rules Going Into Effect Today

COMMERCE DEPARTMENT

National Oceanic and Atmospheric Administration—

32391 6-6-79 / Frozen fried scallops; U.S. standards for grades

32385 6-6-79 / U.S. general standards for fish fillets

32388 6-6-79 / U.S. standards for grades of frozen minced fish blocks

COMMUNITY SERVICES ADMINISTRATION

36181 6-21-79 / Due process rights for applicants denied benefits under CSA-funded programs

ENERGY DEPARTMENT

Federal Energy Regulatory Commission—

38837 7-3-79 / Determination of powerplant design capacity

FEDERAL COMMUNICATIONS COMMISSION

36041 6-21-79 / Adding ports to designated radio protection areas for vessel traffic service purposes

HEALTH, EDUCATION, AND WELFARE DEPARTMENT

Food and Drug Administration—

40888 7-13-79 / New animal drugs for use in animal feed; 2-Acetylamino-5-Nitrothiazole, revocation of portion of rule

LABOR DEPARTMENT

Pension and Welfare Benefit Programs—

37221 6-26-79 / Investment of plan assets under the "Prudence" rule

SECURITIES AND EXCHANGE COMMISSION

34889 6-15-79 / Focus reporting system; Requirements for financial reporting

34884 6-15-79 / Uniform net capital rule

List of Public Laws

Note: No public bills which have become law were received by the Office of the Federal Register for inclusion in today's List of Public Laws.

Last Listing July 20, 1979